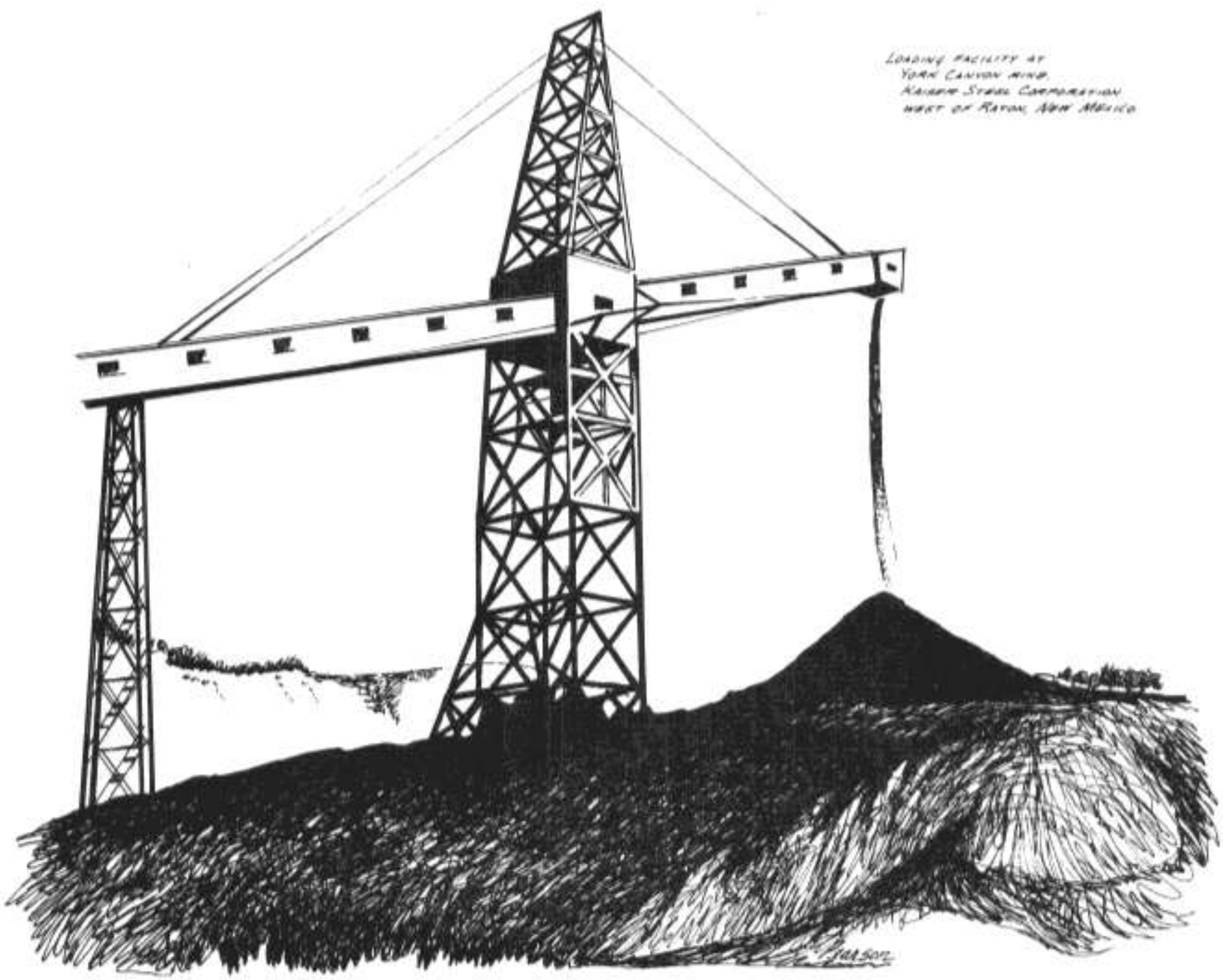
New Mexico's energy resources '77

Office of the State Geologist

by

Emery C. Arnold and others

Jerry Apodaca, Governor of New Mexico

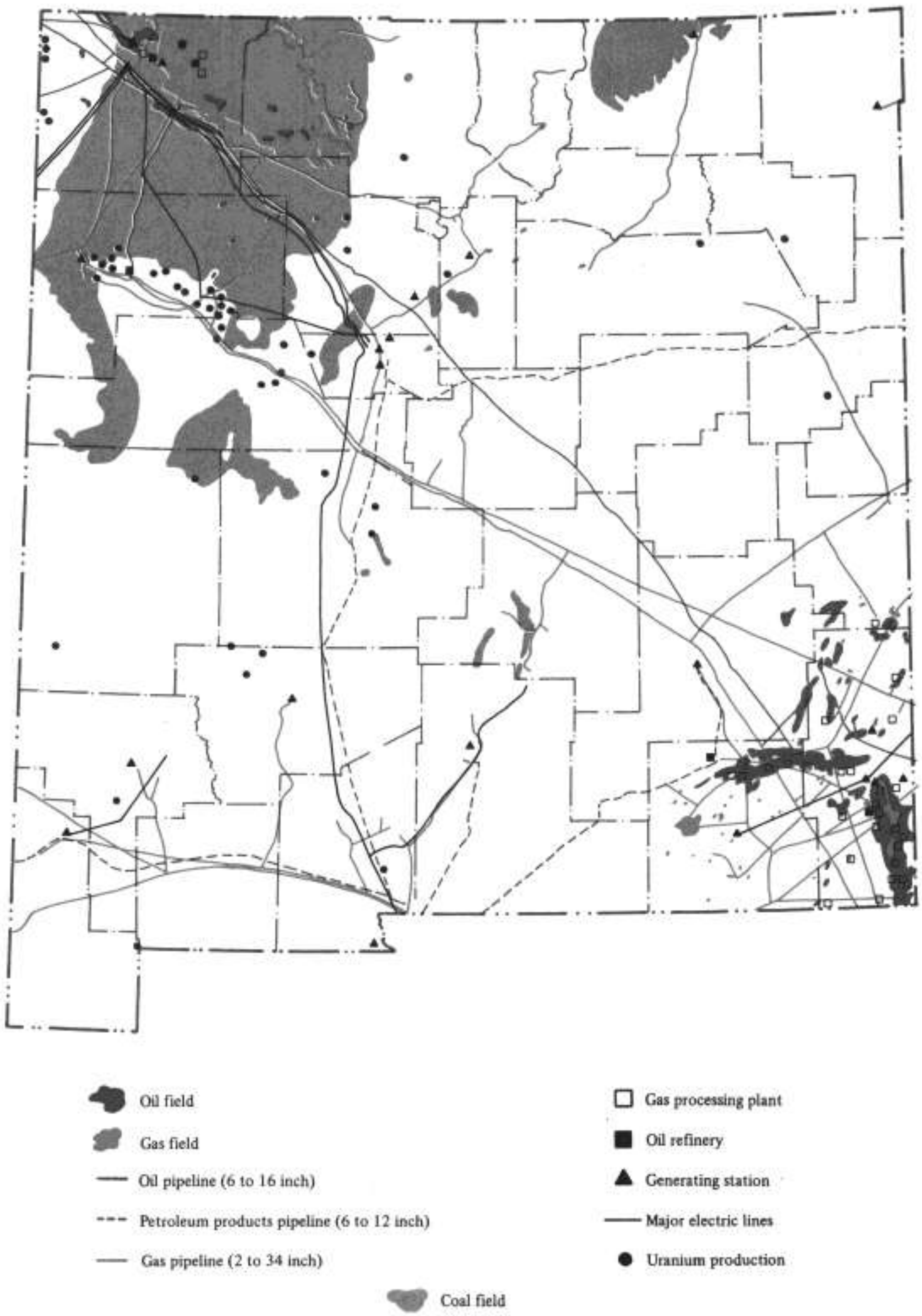


New Mexico Bureau of Mines & Mineral Resources

Circular 167

A DIVISION OF
NEW MEXICO INSTITUTE OF MINING & TECHNOLOGY

1978



FRONTISPIECE—NEW MEXICO'S ENERGY RESOURCES

This map is a small-scale version of Resource Map 2 by the New Mexico Bureau of Mines & Mineral Resources, 1974.

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New Mexico's energy resources '77
—Office of the State Geologist

compiled by
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with contributions by
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Governor of New Mexico

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Preface

It is my privilege to present this report to the Governor of New Mexico and to members of the State Legislature for their use in formulating State energy policy.

The Office of the State Geologist was established by Chapter 289 of the laws of 1975. The office was opened in August 1975; permanent quarters are established at No. 2 Jefferson Place in Santa Fe (Post Office Box 2860, 87501; telephone 505/827-2987). The staff consists of the following:

Orin J. Anderson, *Staff Geologist*
Emery C. Arnold, *State Geologist*
David A. Donaldson, *Staff Geologist*
Kay S. Hatton, *Staff Geologist* James
M. Hill, *Deputy State Geologist* Louise
E. Jiron, *Stenographer* Louie B.
Martinez, *Staff Geologist* Ida
Rodriguez, *Administrative Assistant*
Kathleen M. Simmons, *Secretary*

The Office of the State Geologist is charged with the responsibility of conducting geological studies aimed at determining reserves of known supplies of energy resources, compiling an inventory of such reserves, and conducting geological studies of probable and potential supplies. The office is also charged with cooperating with the New Mexico Bureau of Mines and Mineral Resources in preparing maps, brochures, and pamphlets on known probable and potential sources of energy in New Mexico.

This is the third reserve and production summary published since the office was established and is the first report to contain independently derived oil and gas reserve estimates. Independently derived coal reserve estimates are also being prepared with the help of consultants and will be published in more complete form at a later date.

Personnel from the Bureau of Mines and Mineral Resources have contributed much time, effort, and material to the preparation of this report; their cooperation is appreciated. Sandra C. Feldman, a consulting geologist of Albuquerque, provided a great deal of editorial assistance. I also wish to express my appreciation for advice and assistance received from the New Mexico Oil Conservation Commission, the New Mexico Oil and Gas Accounting Commission, the New Mexico Bureau of Revenue, the State Inspector of Mines, the U.S. Bureau of Mines, and the U.S. Energy Research and Development Administration (ERDA), as well as from the many industry personnel who contributed information and advice.

Effective October 1, 1977, the U.S. Energy Research and Development Administration, the Federal Power Commission, and the Federal Energy Administration no longer exist. Their functions were assimilated into the new U.S. Department of Energy (DOE). Inasmuch as most of the data in this circular had been compiled earlier, these administrative changes could not be shown in the data.

Emery C. Arnold
State Geologist
Office of the State Geologist

Santa Fe
September 28, 1977

Contents

FIGURES

TABLES

Abstract

Production of **crude oil** and **condensate** in New Mexico has declined from the high of 129.2 million barrels in 1969 to 92.1 million barrels in 1976; the decline is expected to continue. **Natural gas** production, which had been increasing until 1975, also experienced a slight decline in 1976. The Blanco Mesaverde Gas Pool in northwest New Mexico is the most prolific gas pool in the state, and an estimated 7,120 billion cubic feet of reserves remain in the pool as of January 1, 1975. The first discovery of commercial natural gas outside the known southeast and northwest provinces was made in Mora County in September 1973; now gas is being produced there from a Dakota Sandstone reservoir. Two new independent estimates of state **oil reserves** are presented along with previously published estimates. **Coal** production totaled 9,980,322 tons in 1976, most of it from the Navajo and San Juan mines. An environmental impact statement is required by the U.S. Department of the Interior on 4.8 million acres in northwest New Mexico before coal leasing and development can continue on Federal land. Production of **U_30,** totaled 6,500 tons in 1976, 46 percent of the U.S. total; New Mexico also ranked first in U308 reserves (357,000 tons in the $30-cost category). Potential **geothermal resources** occur along the Rio Grande Valley and in the west-central and southwest areas; as of September 15, 1977, the U.S. Bureau of Land Management had issued 97 currently active geothermal leases; the State Land Office had issued 185.

Energy in New Mexico and adjacent states

by E. C. Arnold and 0. J. Anderson, *Office of the State Geologist*

Energy production and reserve figures in four energy resource categories are given for New Mexico and adjacent states in table 1. As can be seen, New Mexico has continued to be a highly significant energy-producing state. Although petroleum and natural gas production tend to be dwarfed by Texas production, New Mexico is the largest net exporter of energy among the western states (here taken to include the Rocky Mountain states and those to the west), the only other significant one being Wyoming. New Mexico exported the equivalent of 1,551.5 trillion Btu (British thermal units) in 1975 compared to Wyoming's 1,217.6 trillion Btu. Neither of these figures includes energy content of exported uranium. Although California produced slightly more energy than New Mexico, exclusive of uranium, it consumed twice the amount it produced, and therefore it is a net importer of energy.

Natural gas and uranium are the energy commodities for which New Mexico is most recognized. Presently the state is supplying 46 percent of domestic U30$_8$ production and ranks fourth nationally in natural gas production. Production projections for these two resources

TABLE 1—PRODUCTION AND RESERVES OF OIL, GAS, COAL, AND URANIUM FOR NEW MEXICO COMPARED TO ADJACENT STATES, 1976.

	Crude oil				Total gas				Coal				Uranium			
	Production		Reserves		Production		Reserves		Total production		Strippable reserves		Production		Reserves ($30)	
State	Million bbls	Nat. rank	Million bbls	Nat. rank	Billion cu ft	Nat. rank	Billion cu ft	Nat. rank	Million tons	Nat. rank	Million tons	Nat. rank	Tons U_3O_8	Nat. rank	Tons U_3O_8	Nat. rank
New Mexico	88.05[2]	6	535.5	7	1,219.81	4	11,916.62	6	9,980[5]	14	2,448[6]	11	6,500	1	357,000	1
Texas	1,158.74[2]	1	9,226.2	2	6,895.92	2	64,651.41	1	14,215[4]	11	3,182[6]	10	518[7]	3	44,000	3
Oklahoma	152.05[2]	4	1,186.6	5	1,654.14	3	12,435.33	4	3,299[4]	20	425[6]	21	--	-	--	-
Colorado	37.78[2]	11	251.8	9	178.35	9	1,887.78	10	9,428[4]	15	3,791[6]	8	--	-	--	-
Utah	34.06[2]	12	183.2	12	57.38	17	829.86	-	7,880[4]	17	268[6]	-	--	-	43,000	-
Arizona	0.62[3]	-	--	-	--	-	D.28	-	10,242[4]	13	326[6]	-	--	-	--	-

1. To convert to trillion Btu (TBTU) the following conversion factors are included:

   180,000 bbls oil = 1 TBTU
   1 billion cu ft of gas = 1 TBTU
   50,000 short tons of coal (approx.) = 1 TBTU

Because the energy value of uranium is so conditional it was omitted at this time.

2. API
3. Western Oil Reporter, April 1977
4. 1977 Keystone Industry Coal Manual
5. New Mexico Bureau of Revenue
6. U.S. Bureau of Mines
7. Texas Railroad Commission

TABLE 2—Production of oil and natural gas in New Mexico, 1960 through 1976 (source: NMOCC).

Year and area	*Barrels*				*Thousand cubic feet*		
	Oil	*Condensate*	*Total oil and condensate*	*Water*	*Casinghead gas*	*Dry gas*	*Total gas*
NW	13,430,845	1,374,351	14,805,196	915,768	31,266,992	342,133,828	373,400,820
SE	91,149,978	1,409,974	92,559,952	84,017,567	262,155,625	186,358,171	448,513,796
1960, total	104,580,823	2,784,325	107,365,148	84,933,335	293,422,617	528,491,999	821,914,616
NW	14,210,632	1,525,358	15,735,990	1,862,902	39,954,895	319,541,175	359,496,070
SE	95,596,439	1,220,972	96,817,411	97,512,336	269,373,304	157,725,609	427,098,913
1961, total	109,807,071	2,746,330	112,553,401	99,375,238	309,328,199	477,266,784	786,594,983
NW	9,181,861	1,659,507	10,841,368	3,839,406	35,895,143	304,909,639	340,804,782
SE	97,225,296	1,261,389	98,486,685	113,139,221	275,932,682	170,015,467	445,948,149
1962, total	106,407,157	2,920,896	109,328,053	116,978,627	311,827,825	474,925,106	786,752,931
NW	7,942,818	1,874,934	9,817,752	4,470,887	27,183,166	321,553,533	348,736,699
SE	98,794,993	1,370,312	100,165,305	127,283,521	272,556,376	171,932,132	444,488,508
1963, total	106,737,811	3,245,246	109,983,057	131,754,408	299,739,542	493,485,665	793,225,207
NW	7,443,260	2,550,525	9,993,785	7,131,448	20,991,913	405,718,222	426,710,135
SE	102,508,438	1,361,185	103,869,623	138,760,709	270,538,055	195,430,490	465,968,545
1964, total	109,951,698	3,911,710	113,863,408	145,892,157	291,529,968	601,148,712	892,678,680
NW	8,776,902	2,804,888	11,581,790	10,600,522	18,467,730	441,561,504	460,029,234
SE	105,966,181	1,618,506	107,584,687	150,261,064	276,863,641	208,128,648	484,992,289
1965, total	114,743,083	4,423,394	119,166,477	160,861,586	295,331,371	649,690,152	945,021,523
NW	8,159,673	3,196,280	11,355,953	13,533,781	15,222,739	483,275,803	498,498,542
SE	111,015,456	1,819,342	112,834,798	158,177,814	286,076,861	228,035,560	514,112,421
1966, total	119,175,129	5,015,622	124,190,751	171,711,595	301,299,600	711,311,363	1,012,610,963
NW	7,533,818	3,528,057	11,061,875	16,198,320	13,928,329	523,356,226	537,284,555
SE	113,060,912	1,879,664	114,940,576	167,575,219	281,722,938	236,644,443	518,367,381
1967, total	120,594,730	5,407,721	126,002,451	183,773,539	295,651,267	760,000,669	1,055,651,936
NW	6,732,250	3,673,081	10,405,331	17,020,379	13,140,201	580,374,026	593,514,227
SE	115,700,459	2,505,535	118,205,994	195,073,824	279,612,600	277,239,086	556,851,686
1968, total	122,432,709	6,178,616	128,611,325	212,094,203	292,752,801	857,613,112	1,150,365,913
NW	6,011,237	3,035,489	9,048,726	16,929,938	12,964,592	538,010,671	550,975,263
SE	117,722,236	2,455,899	120,178,135	210,505,804	282,222,689	280,642,531	562,865,220
1969, total	123,735,473	5,491,388	129,226,861	227,435,742	295,187,281	818,653,202	1,113,840,483
NW	5,780,167	2,905,943	8,686,110	18,593,311	11,066,422	513,961,890	525,028,312
SE	117,181,123	2,280,664	119,461,787	226,808,233	292,907,627	305,519,255	598,426,882
1970, total	122,961,290	5,186,607	128,147,897	245,401,544	303,974,049	819,481,145	1,123,455,194
NW	6,012,907	2,801,992	8,814,899	18,860,437	11,573,567	546,546,676	558,120,243
SE	107,708,035	1,887,036	109,595,071	206,386,656	291,253,975	298,056,323	589,310,298
1971, total	113,720,942	4,689,028	118,409,970	225,247,093	302,827,542	844,602,999	1,147,430,541
NW	5,730,714	2,874,298	8,605,012	20,415,149	12,314,515	574,019,873	586,334,388
SE	99,665,888	2,254,324	101,920,212	196,174,211	259,535,532	351,899,738	611,435,270
1972, total	105,396,602	5,128,622	110,525,224	216,589,360	271,850,047	925,919,611	1,197,769,658
NW	5,175,343	2,394,207	7,569,550	20,659,128	12,932,204	537,186,284	550,118,488
SE	91,233,655	2,182,481	93,416,136	199,979,510	250,718,587	398,702,355	649,420,942
1973, total	96,408,998	4,576,688	100,985,686	220,638,638	263,650,791	935,888,639	1,199,539,430
NW	5,599,465	2,401,954	8,001,419	26,544,506	14,612,336	532,780,048	547,392,384
SE	88,483,452	2,210,094	90,693,546	204,598,067	289,089,197	393,191,355	682,280,552
1974, total	94,082,917	4,612,048	98,694,965	231,142,573	303,701,533	925,971,403	1,229,672,936
NW	4,378,951	2,118,324	6,497,275	24,324,927	14,046,453	504,499,980	518,546,433
SE	86,374,571	2,190,689	88,565,260	208,391,779	291,662,510	392,897,887	684,560,397
1975, total	90,753,522	4,309,013	95,062,535	232,716,706	305,708,963	897,397,867	1,203,106,830
NW	3,721,564	2,274,973	5,996,537	26,825,257	10,157,080	517,649,826	527,806,906
SE	83,715,295	2,417,043	86,132,338	212,782,479	269,673,315	403,395,146	673,068,461
1976, total	87,436,859	4,692,016	92,128,875	239,607,736	279,830,395	921,044,972	1,200,875,367

are, however, vastly different. U_3O_8 production in New Mexico is expected to increase dramatically during the next decade to meet electric utility demand, while natural gas production is expected to decrease significantly as reserves are depleted.

Crude oil production for 1976 was 87.4 million bbls (barrels), and condensate production increased the total to 92.1 million bbls. This placed New Mexico sixth nationally, behind Texas, Louisiana, California, Oklahoma, and Wyoming. Future production levels in New Mexico will depend very heavily upon the success and expansion of the enhanced recovery projects underway in Eddy and Lea Counties, as well as upon discovery rates.

Coal production in New Mexico increased five percent in 1976 to just under 10 million tons per year (table 1). Most western coal-producing states have experienced production increases in the past several years; however, none has matched Wyoming, which went from 14 million tons in 1973 to an estimated 30 million tons in 1976. New Mexico has just begun to experience the coal boom; production will probably double by 1982. Markets for New Mexico steam coal appear to be developing in other southwestern states whose own coal resources are limited.

Coal is New Mexico's long-range fuel. Most experts agree that long after other state energy resources have begun to wane, coal will be the mainstay of the energy-extractive industry. The six billion tons of reserves to a depth of 250 ft in the San Juan Basin convert to approximately 108 quadrillion Btu (based on 9,000 Btu per lb coal), while the remaining oil and gas reserves together convert to less than 15 quadrillion Btu.

None of the states listed in table 1 are producing energy from geothermal resources; however, New Mexico may be closer than any of the others to tapping this energy resource.

Oil and gas

by E. C. Arnold, J. M. Hill, D. A. Donaldson, and L. B. Martinez, *Office of the State Geologist,*
R. W. Foster, *New Mexico Bureau of Mines and Mineral Resources,* and
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Oil production

Southeast New Mexico

Production of crude oil in southeast New Mexico in 1976 was 83.72 million bbls, which is 3.1 percent below 1975 production (table 2). Since the peak in 1969 and 1970, oil production has declined 7.5-8.5 percent in 1971 through 1973, and 2.4-3.1 percent in 1974 through 1976. For the first five months of 1977, the decline rate was 6.2 percent. The lower decline rates for the 1974-1976 period resulted from a variety of causes, such as production from workovers of old wells that had ceased to produce and were recompleted in different zones or formations to establish new production. Many of these re-completions were in Yeso Group formations in the Lower Permian. Another reason for the smaller production decline was the completion of numerous marginal wells, generally capable of producing less than 15 bbls of oil per day. The marginal production zones are usually found in areas adjacent to currently producing wells, toward the periphery of pools where pays are thinner, or in areas where reservoir characteristics are below average.

Prior to 1974, wells that produced less than 10 bbls per day were not considered commercial. In 1974 the price of stripper oil increased by a factor of 3-4, and this brought on the drilling of many marginal wells. Another factor that helped keep production rates up in 1974 and 1975 was the increased production from the Empire Abo field. This field has very high production capabilities, and in 1974 a secondary recovery project was initiated utilizing a gas pressure maintenance system. Production from the Empire Abo field in 1973, 1974, 1975, and 1976 was 9.74, 13.38, 15.22, and 15.30 million bbls respectively.

In 1976 oil production reported from 272 secondary recovery projects was 37.76 million bbls; this production is approximately equivalent to 1975 production. The number of projects remained the same. Secondary oil production accounts for 45 percent of the total southeast crude oil production. Of the total secondary production, 15.13 million bbls of oil (40 percent) came from the Empire Abo Pool, which is actually a gas pressure maintenance project.

Northwest New Mexico

Oil production in northwest New Mexico continued to decline. Crude oil production for 1976 was only 3,721,564 bbls. This was a decrease of 657,387 bbls from 1975 production. Two major factors have contributed to the continued decrease in crude oil production in the San Juan Basin. The first factor is the large portion of the basin production which comes from secondary recovery, mainly from nearly depleted Gallup reservoirs. The other major factor is the lack of major oil discoveries in the last few years. Even the added production from the newly discovered Entrada Pools has not been able to offset the annual production decline.

Gas production

Southeast New Mexico

Casinghead gas production for 1976 in southeast New Mexico was 269.7 billion cu ft, down 7.5 percent from the 1975 figure. The continuing rapid decline is probably due to the advanced depletion of many older pools and the expansion of waterflooding operations. Dry gas production for 1976 was 403.4 billion cu ft, which is a 2.7 percent increase over 1975. Pennsylvanian gas development, primarily in Eddy County, accounted for most of the increase; 57 percent of the 187 gas completions were in the Pennsylvanian. Condensate production was up nearly 10 percent to 2.42 million bbls. For the first five months of 1977, dry gas production had declined less than one percent, and condensate production declined slightly over one percent.

Northwest New Mexico

Total gas produced in northwest New Mexico for 1976 was 527.8 billion cu ft. Dry gas production contributed 98 percent (517.6 billion cu ft) to this total, and only two percent (10.2 billion cu ft) came from casing-head gas production. Total 1976 gas production was a net increase of 9.3 billion cu ft over 1975 production. Much of this net increase came from new infill production in the Blanco Mesaverde Gas Pool. The 1976 production for the Blanco Mesaverde Pool increased by 20.6 billion cu ft over 1975. This increase offset the drop in annual production from the Basin Dakota Gas Pool. The Basin Dakota 1976 annual production decreased by 10.2 billion cu ft from 1975 production. A comparison of 1975 and 1976 annual production for the Blanco Mesaverde and Basin Dakota Pools is shown in table 3.

Natural gas liquid production

In 1976 there were 35 liquid extraction plants operating in New Mexico. Twenty-nine plants were located in southeast New Mexico, and the remaining six were in the northwest section of the state. The total plant intake for the 35 plants was over a trillion cubic feet. Table 4 shows extraction plant production for 1975 and 1976. A comparison shows that the 1976 total production increased by over 2 million bbls. Much of this increase was in gasoline production.

TABLE 3—1975-76 PRODUCTION IN BLANCO MESAVERDE AND BASIN DAKOTA GAS POOLS (source: NMOCC).

	Production (thousand cu ft)			
	1975		1976	
Pool	Annual	Cumulative	Annual	Cumulative
Blanco Mesaverde Gas Pool				
Rio Arriba Co.	61,313,513	1,183,668,271	62,037,399	1,245,694,700
San Juan Co.	155,575,418	2,977,650,341	175,454,474	3,153,123,247
Total	216,888,931	4,161,318,612	237,491,873	4,398,817,947
Basin Dakota Gas Pool				
Rio Arriba Co.	55,214,046	641,622,683	52,138,120	693,789,485
San Juan Co.	107,040,902	1,959,702,694	99,964,554	2,059,667,271
Total	162,254,948	2,601,325,377	152,102,674	2,753,456,756

TABLE 4—1975-76 PRODUCTION FOR EXTRACTION PLANTS IN NEW MEXICO (source: NMOCC).

	Production (bbls)	
	1975	1976
Gasoline	17,434,531	19,780,162
Butane	8,291,666	8,003,637
Propane	9,714,182	9,805,365
Total	35,440,379	37,589,164

Drilling and development

Southeast New Mexico

In 1976 development drilling continued much the same as in 1975. A majority of the activity was located in and around established oil and gas pools or along known production trends. Completions of old well workovers also continued in 1976. The combination of Queen, Grayburg, and San Andres Formations had the most oil completions with 152, followed by the Yeso Group of Paddock, Blinebry, Tubb, and Drinkard, with 75 oil completions. Most gas completions were in the Pennsylvanian-78 in the Atoka-Morrow and 28 in the Upper Pennsylvanian. There were 784 completions, which included 431 oil wells, 187 gas wells, and 166 dry holes (table 5). The total footage drilled was 3.76 million ft. In 1976, 27 new oil pools were created, with a dedicated acreage of 5,320. Of these 27 new oil pools, six pools had wells producing from formations other than the Permian. Five pools were producing from the Pennsylvanian and one pool from the Fusselman. In 1976 there were 42 new gas pools created, with a dedicated acreage of 21,120. Only five of these were producing from formations other than the Pennsylvanian: one from Queen, one from Delaware, and three from Wolf-camp gas pools. Most of the 1976 oil and gas development has been along known production trends or from the completion of wells in formations not producing before but known to be productive. There were 71 ex-

TABLE 5—OIL AND GAS WELL COMPLETIONS IN SOUTHEAST NEW MEXICO (source: NMOCC).

	Number of wells				% Inc.
Year	Oil	Gas	Dry	Total	or dec.
1971	392	58	158	608	
1972	422	94	150	666	+10
1973	240	178	182	600	-10
1974	382	249	173	804	+34
1975	422	224	133	779	- 3
1976	431	187	166[1]	784[1]	+ 1

1. Includes temporarily abandoned wells

tensions to oil pools, which increased producing acreage by 16,400 ac, and 45 extensions to gas pools, which increased producing acreage by 34,600 ac.

Northwest New Mexico

Northwest New Mexico well completions in 1976 were down from the previous year in both oil and gas. The Federal Power Commission's new gas price hike came too late in the year to significantly increase drilling activity in the San Juan Basin. This price increase, passed in late July 1976, raised the ceiling price for newly discovered interstate gas to $1.42 per thousand cu ft. The price hike occurred after the various producing companies had approved their yearly drilling budgets. One other factor that could have contributed to a decrease in gas completions was the controversy between pipeline companies and former leaseholders over the overriding royalty payments. Until this legal problem is resolved, the pipeline-producing companies may take a more conservative attitude toward well completions.

There were 12 fewer oil wells and nine fewer gas wells completed in 1976 than in 1975. The greatest number of oil completions occurred in the Horseshoe Gallup Pool, with 12 wells. Within the last three years, several Entrada oil pools have been discovered. By August 1, 1977, there were six Entrada pools producing in the San Juan Basin, and two of the six pools were brought into production in early 1977. These Jurassic-age pools are located in the southwest portion of the San Juan Basin in San Juan, McKinley, and Sandoval counties. The six pools are scattered along a 36-mi northwest-trending zone. All of the pools have similar reservoir characteristics with good porosity (averaging about 23 percent) and good permeability (about 300 millidarcies). Production is from an active water drive. The oil has been trapped within small structural highs or noses at the top of the formation. A physical characteristic of the oil has caused some marketing problems in the past. The oil has a high pour point and, in order to produce it, special production equipment is required. Table 6 shows the annual and cumulative production for the three pools that were producing during 1976. The three other pools were not added until 1977.

The total 1976 Entrada production was 397,236 bbls of oil. Table 7 lists the six Entrada pools, the number of producing wells in each pool, the dates when the pools were established, and their locations. It is expected that exploration and development will continue in this area and that additional discoveries will be made.

TABLE 6—ENTRADA OIL POOL PRODUCTION, 1976 (source: NMOCC).

Pool	Production (bbls) Annual	Cumulative
Media	100,148	913,515
Media Southwest	187,141	286,267
Eagle Mesa	109,947	158,113
Total	397,236	1,357,895

TABLE 7—DATA ON ENTRADA OIL POOL (source: NMOCC).

Pool	Date established	Number wells	Location Sec., Twp., Rge.
Media	5/54	7	14,15,22,23, T.19N., R.3W.
Media, Southwest	9/74	3	22, T.19N., R.3W.
Eagle Mesa	11/75	4	11,12,13,14, T.19N., R.4W.
Ojo Encino	12/76	4	21, T.20N., R.5W.
Papers Wash	3/77	4	15, T.19N., R.5W.
Snake Eyes	5/77	1	20, T.21N., R.8W.

As expected, the greatest number of gas completions occurred in the Blanco Mesaverde Gas Pool, with 124 wells. Most of these gas completions were infill wells. The second largest number of gas completions occurred in the South Blanco Pictured Cliffs Pool, with 40 wells.

Total wells drilled in northwest New Mexico increased in 1976 by 21 wells over the number drilled in 1975 (table 8). This increase can be attributed in part to increased exploration drilling. There were 42 more dry holes drilled in 1976 than in 1975. A comparison of drilling activity for the first six months of 1976 with that of 1977 shows a marked increase in drilling in most categories in 1977. As shown in table 9, northwest New Mexico gas completions for the first six months of 1977 were up 100 percent over the same 1976 period, and oil completions were up by 12 percent. This increased activity is expected to continue through 1977.

Blanco Mesaverde Gas Pool reserve

The Blanco Mesaverde Gas Pool in northwest New Mexico is the state's most prolific gas pool. In 1976, 46 percent of the dry gas production in the San Juan Basin came from this pool, representing 26 percent of the dry gas produced in the state that year. Future gas production in the state will obviously be heavily affected by the remaining reserves and future production rates of the pool. Because of the highly variable nature of the reservoir, the reserve estimates that have been made public also exhibit wide variations. In our opinion it is impos-

TABLE 8—OIL AND GAS COMPLETIONS IN NORTHWEST NEW MEXICO (source: NMOCC).

Year	Number of wells Oil	Gas	Dry	Total	% inc. or dec.
1971	49	182	72	303	
1972	40	260	105	405	+34
1973	33	434	65	532	+31
1974	62	332	57	451	-15
1975	63	340	31	434	- 4
1976	51	331	73	455	+ 5

TABLE 9—Oil and gas well drilling comparison, first 6 months 1976 and 1977 (source: NMOCC).

	Jan.-June 1976	Jan.-June 1977	% change between first half 1976 and 1977
Southeast New Mexico			
New Locations	332	444	+ 34
Oil Completions	239	208	- 13
Gas Completions	102	111	+ 9
Dry Holes	95	80	- 16
Northwest New Mexico			
New Locations	304	486	+ 60
Oil Completions	25	28	+ 12
Gas Completions	131	262	+100
Dry Holes	48	24	-100
Total New Mexico			
Completions	640	713	+ 11
Footage Drilled	2,883,000	3,365,000	+ 17

sible to accurately estimate reserves in this pool without employing both geological and engineering methods in concert. Even then, different investigators arrive at different answers, particularly in assessing the effects of in-fill drilling on total recoverable reserves. The estimate presented in this report is made in response to the statute which established the Office of State Geologist in January 1975. This statute directs the office to conduct studies aimed at determining reserves and life expectancy of natural sources of energy in the state "including fossil fuels, radioactive minerals and geothermal energy." The study made by this office of the Blanco Mesaverde Gas Pool is essentially a pressure-decline versus cumulative-production study, although adjustments have been made based on years of geological study of the reservoir characteristics.

History

Production of oil and gas in the San Juan Basin has not always paralleled the discovery of new fields, as is demonstrated by the history of the Blanco Mesaverde Gas Pool. In 1927 gas was discovered by the Huntington Park Oil Company in the Mesaverde Group in T. 30 N., R. 9 W., a few miles northeast of the village of Blanco. The well remained shut in until 1929, when a 4-inch gas line was completed to serve the town of Aztec. Subsequent development of the field was suspended for 17 years until M. J. Florance began a new drilling and development program in 1946. By the end of 1950 there were 30 wells in the pool. With the completion of the El Paso Natural Gas Company pipeline to California in 1951, development of gas in the Mesaverde producing zone was vigorously renewed. Initially, several pools, including the La Plata, South La Plata, and Largo, were established in widely separated portions of the reservoir. These individual pools were all combined into the Blanco Mesaverde Gas Pool when it became evident from development that gas was continuously present across the entire area, which measures about 70 mi long and 40 mi wide at its maximum width and includes about 1,450 sq mi. By the end of 1953, the pool contained almost 500 producing wells; four times that many wells were producing by the end of 1965. At the end of 1974, the pool contained 2,100 producing wells, an increase of only 100 wells in 10 years (table 10). These figures reflect the fact that the more productive portions of the pool are virtually fully developed to 320-ac well density.

In the fall of 1974, the El Paso Natural Gas Company filed for a hearing before the NMOCC (New Mexico Oil Conservation Commission) to consider infill drilling to 160-ac well density in the pool. Many operators contended that infill drilling was necessary in order to prevent leaving substantial quantities of unrecovered gas in the reservoir. The Commission approved the application in November 1974, and a new drilling program was instituted. By the spring of 1977, 250 infill wells had been drilled in the pool. Production increased from 216 billion cu ft in 1975 to 237 billion cu ft in 1976, and the increase was entirely due to infill production. Cumulative pool production to December 31, 1976, was 4,399 billion cu ft. Table 10 is a tabulation showing historical production in the pool and the number of wells that produced each year since 1955.

TABLE 10—Annual gas production for New Mexico portion of Blanco Mesaverde Gas Pool, 1955 through 1976 (source: NMOCC).

Year	No. Wells	Gas prod. (billion cu ft)	Condensate prod. (bbls)
1955	898	128.8	339,910
1956	1114	142.7	404,983
1957	1393	212.4	758,153
1958	1690	167.6	592,720
1959	1751	166.8	618,423
1960	1846	192.6	716,373
1961	1898	160.8	571,058
1962	1942	131,9	454,639
1963	1964	135.0	493,749
1964	1977	165.4	645,105
1965	1995	181.0	748,964
1966	2015	192.0	818,666
1967	2033	200.8	918,237
1968	2041	221.6	1,028,742
1969	2052	215.6	977,398
1970	2066	205.7	978,234
1971	2069	227,1	1,097,713
1972	2084	250.1	1,222,597
1973	2095	230.9	999,804

Year	No. Wells	Gas prod. (billion cu ft) Annual	Gas prod. (billion cu ft) Cumulative	Condensate prod. (bbls) Annual	Condensate prod. (bbls) Cumulative
1974	2100	226.8	3,944.4	1,085,541	15,860,459
1975	2203	216.9	4,161.3	948,519	16,809,059
1976	2321	237.5	4,398.8	1,065,676	17,849,174

Stratigraphy

The term "Mesaverde producing zone" is here used in a restricted sense to describe the producing zone in the Blanco Mesaverde Gas Pool. Within the gas-producing area, the Mesaverde producing zone consists of the Point Lookout Sandstone, the Menefee Formation, and the Cliff House Sandstone, in ascending order. In 1977 the NMOCC extended the vertical limits of the pool to include fracture zones containing gas in the Lewis Shale, which is stratigraphically above the Mesaverde Group. Deposition of the formations comprising this group occurred as a result of a regressive-transgressive cycle along the western edge of a segment of the interior sea that covered a large portion of western North America during Late Cretaceous time. The Point Lookout Sandstone was deposited during the regressive cycle when the sea retreated to the northeast, building beach sands seaward. Along the line of maximum retreat, the Point Lookout Sandstone becomes fine grained and gradually grades into Mancos Shale. This was followed by a transgressive cycle when the sea again encroached on the land in a southwesterly direction, resulting in the deposition of the Cliff House Sandstone, which rises stratigraphically to the southwest. The swampy environments that were associated with Point Lookout and Cliff House deposition resulted in the formation of the mudstones, siltstones, channel sands, and coals of the Menefee Formation.

The Lewis Shale is the deep-water equivalent of the Cliff House Sandstone, while the Mancos Shale is the deep-water equivalent of the Point Lookout Sandstone. Therefore, the Mesaverde producing zone in the central and northeastern portions of the basin, where the Blanco Mesaverde Gas Pool is located, is a wedge of sandstone and continental clastic sediment lying between the converging Lewis and Mancos marine shales. The direction of convergence is from southwest to northeast. The lower part of the Point Lookout Sandstone is transitional with the Mancos Shale and consists of thin-bedded sandstones interbedded with the shale. The upper part contains a massive member that is extensive and contains a large portion of the gas in the pool.

The Cliff House Sandstone is transitional with the overlying Lewis Shale and intertongues with both Lewis Shale and Menefee Formation. Individual lenses in the Cliff House are smaller in lateral extent than Point Lookout lenses, and gas production is less continuous. Gas also occurs in better porosity zones in the Menefee Formation.

The thickest and most prolific sandstone section of the Mesaverde producing zone occurs in the central portion of the pool; this section is elongate in a northwest-southeast direction, roughly paralleling the structural strike of the basin. Effective pay sand, recoverable reserves, and productive capacity generally decrease in a northeast or southwest direction from this central portion, and production becomes very marginal toward the edges of the pool. The gross thickness of the Mesaverde producing zone on the southwestern edge of the pool is 700-1,000 ft; the pay interval thins to the northeast, and at the east edge of the pool total thickness drops to below 300 ft. Grain size, permeability, and porosity of the pay sands also decrease in a northeasterly direction. The portion of gross sand that is counted as net pay varies from about 50-150 ft in areas with average to high production but thins to as little as 30 ft in marginal areas approaching the pool boundaries. On the southwest edge of the pool the productive limit is usually marked by a line of water encroachment. Sandstone body porosities range from 4-14 percent and average about nine percent in the pay zone. The mean permeability of the Cliff House Sandstone is about 0.5 millidarcy, and Point Lookout permeability averages about 2 millidarcies (Pritchard, 1973). Natural fracturing also influences well productivity. Figs. 1 and 2 (in pocket) show reserves and production variations across the pool.

Structure

The Blanco Mesaverde Pool is located within the structural element of the San Juan Basin that has been referred to (Kelley, 1950) as the "central basin." The central basin is designated as the floor or bottom of the San Juan Basin proper and lies within the monocline that bounds it on the north, east, and west. The central basin has a long, gently dipping south rim and a relatively short, more steeply dipping north rim. The axis or low point of the basin strikes northwesterly, a little north of Gobernador, extending across T. 31 N., R. 4-6 W. and T. 32N., R. 6 and 7 W.

The Blanco Mesaverde Pool occupies a large segment of the gently dipping southwest limb of the central basin. The pool extends northwesterly from T. 26 N., R. 2 W. (Rio Arriba County) to T. 32 N., R. 13 W. (San Juan County) for about 70 mi along the basin strike. The pool also extends into La Plata County, Colorado, north of R. 6 through 12 W. for a distance of 10 to 12 mi. The maximum pool width (nearly 40 mi) coincides with the approximate center of the pool. Gas occurs across the structural low point or bottom of the basin and extends a short distance up the more steeply dipping northeast limb. However, about 95 percent of the pool is on the southwest limb. There is approximately 1,200 ft of structural relief across the pool. Gas accumulations in the Mesaverde producing zone are downdip from water accumulations which encroach from the southwest edge of the pool. It has been postulated that down-dip gas occurrence resulted from a reversal of attitude in the reservoir subsequent to accumulation (Silver, 1950). Water encroachment extends further northeast in the Cliff House Sandstone than in the Point Lookout Sandstone, and toward the southwest edge of the pool many wells are completed only in the Point Lookout because the Cliff House was found to be water productive.

Gas reserve estimates

VOLUMETRIC RESERVE ESTIMATES—The Blanco Mesaverde Pool was first prorated in 1955 when about 800 wells had been completed. Volumetric reserve studies were made at that time to determine a proper proration formula. Reserve estimates made by the NMOCC staff indicated a high of 28 million cu ft per ac, a low of 12 million cu ft per ac, and an average of 17 million cu ft per ac, or 5.4 billion cu ft for a 320-ac tract. The 800 wells then in the pool were naturally located in the better portion, and this estimate seems to have proven quite accurate. However, the average declined as the pool was extended outward into poorer producing zones where reservoir sands were thinner, and where porosities and permeabilities were lower.

VARIATIONS IN PREVIOUS RESERVE ESTIMATES—AS is often the case with low permeability reservoirs, reserve estimates made by various companies and agencies vary greatly. An engineering firm retained by the El Paso Natural Gas Company to present testimony on infill drilling before the NMOCC in the fall of 1974 estimated that the total original recoverable reserve, with the pool developed on 320-ac spacing, was about 8,700 billion cu ft. The firm estimated that approximately 6,000 billion cu ft of recoverable reserve would be added to that total by drilling to 160-ac well density, bringing the total to over 14,000 billion cu ft. In order to attain such a reserve, projected production life required for individual wells exceeded 150 years in many cases. The estimated 20-year production was just over 3,000 billion cu ft if the pool were left on 320-ac well density, with an additional 4,000 billion cu ft to be produced in 20 years if the pool were developed to 160-ac well density over a 10-year period. Others expressed opinions scaling down the estimated reserves to be added by infill drilling to as low as 1,000 billion cu ft.

The API (American Petroleum Institute) does not publish gas reserves on a pool basis; however, their total dry gas reserve estimate for the San Juan Basin as of January 1, 1975, (for comparison purposes) was 7,533 billion cu ft. Although the API does not publish individual pool reserves or explain very fully the parameters used in reserve calculations, it does not appear likely that the 7,533 billion cu ft reserve estimate anticipated additional volumes of recoverable gas that would be added by infill drilling. Later reserve estimates published by API indicate that substantial upward revisions are being made in the San Juan Basin proven gas reserve, although there is still not sufficient information to indicate whether or not this increase is influenced by proposed infill drilling programs. The API proven dry gas reserve estimate for **all** of northwest New Mexico as of December 31, 1975, was 7,698 billion cu ft, which is up over 100 billion cu ft, even though 504 billion cu ft were produced during 1975.

In 1974 the FEA (Federal Energy Administration) was directed by Congress and the President to provide a complete and independent analysis of the nation's oil and gas resources. In response to this request, the "Final Report on Oil and Gas Reserves, Resources, and Production Capacities" was issued in October 1975. As part of the report, pressure-decline versus cumulative-production studies (as well as production capacity studies) were made in the Basin Dakota and "Blanco field." The "Blanco field" designation included not only the Blanco Mesaverde Pool but also all Pictured Cliffs and Fruitland Pools. Therefore, the total for the two classifications would approximate 98 percent of the proven dry gas reserves in northwest New Mexico. The FEA estimate was 2,150 billion cu ft for the Basin Dakota field and 3,498 billion cu ft for the "Blanco field" for a total proven reserve of 5,648 billion cu ft—about 2,000 billion cu ft under the API estimate. The study did recognize that extremely low permeability problems made pressure data unreliable. The FEA concluded that average reservoir parameters, which had been quoted to them, would suggest a much higher reserve than indicated by the pressure-decline study. Although recognizing the pressure stabilization problem, they did not use a correcting factor.

RESERVE ESTIMATES CALCULATED BY THE OFFICE OF THE STATE GEOLOGIST—The reserve estimates presented in this report also make use of pressure-decline versus cumulative-gas-production studies. Bottom-hole pressure values were available on most of the wells for the initial pressure and the annual pressure from 1970 through 1974. In most cases this provided usable pressure-decline data, although interpretation of some of the data might lead to disagreements. Two different programs were used in calculating pool reserves. The first approach entailed averaging bottom-hole pressure information for wells located in each township, including the initial bottom-hole pressure for each of the wells and yearly annual bottom-hole pressures from 1970 through 1974. The annual shut-in pressures were measured after a 7-day shut-in period as required by NMOCC testing regulations. Cumulative production for wells located in each township for the years 1970 through 1974 was then secured, and a curve for each township was constructed where bottom-hole pressures were plotted against cumulative production for the township (fig. 3). A 50 psi abandonment pressure was utilized. In this way a total original reserve for each township was estimated.

While it was considered that results obtained in this fashion were valid for townships having similar reservoir characteristics throughout, some townships were obviously underlain by acreage containing a wide variation in per-acre reserves. In considering these townships, use of the averaging process might give distorted results, and so a parallel study of the pool was made, using pressure data and cumulative production from individual wells; thus a plot for each well was obtained (fig. 4). Results from the two methods differ by only four percent as a whole. In the final analysis, results from the individual well study have been used in some townships

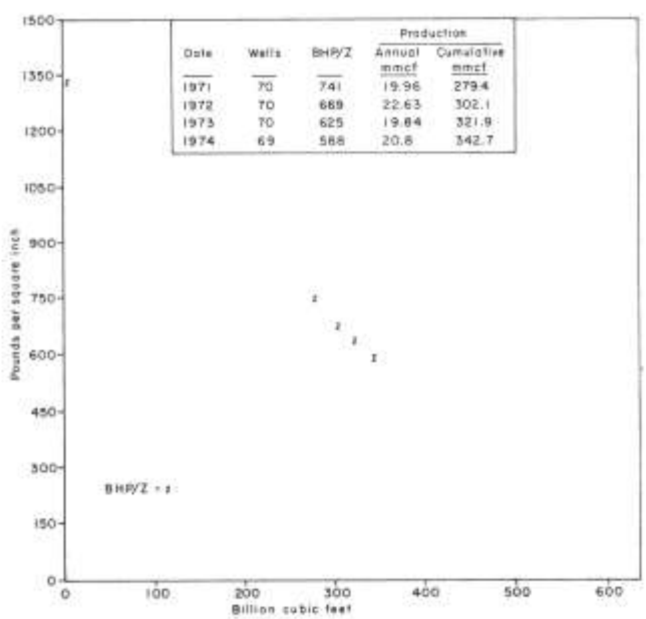

FIGURE 3—PRESSURE PRODUCTION DECLINE FOR ONE TOWNSHIP IN BLANCO MESAVERDE GAS POOL.

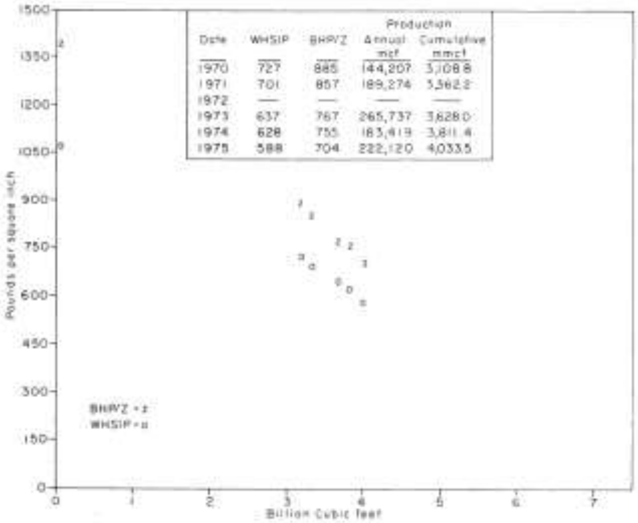

FIGURE 4—PRESSURE PRODUCTION DECLINE CURVE FOR ONE WELL IN BLANCO MESAVERDE GAS POOL (location: unit B, sec. 6, T. 31 N., R. 10 W.).

and from the township study in others, depending upon the characteristics of the reservoir across each township. As a result, the total pool reserve is about 4.5 percent larger than it would have been using the individual well method, and about one percent larger than it would have been using the township method.

Past experience in the Blanco Mesaverde Pool has shown that rather steep pressure gradients develop around each wellbore during production, causing unreliable pressure measurements. Unless a stabilization correction is made, reserve estimates will almost certainly be low, even though a 7-day shut-in pressure is utilized. We have determined that this correction should be approximately 15 percent and have, therefore, corrected the remaining reserves by that amount. This correction results in an original pool reserve of 8,166 billion cu ft. When the pool production through January 1, 1975, is deducted, the remaining recoverable reserve is 4,223 billion cu ft as of the beginning of 1975, assuming a 320-ac drilling density.

In order to estimate the amount of recoverable reserve that will be added to the pool by infill drilling, we instituted a study of pressure information from the first 250 infill wells drilled in the pool. This study included all the wells for which such data was available as of May 1, 1977, and consisted of infill wells drilled during 1975 and 1976. The wells were scattered over 25 of the 57 townships in the pool, although by far the larger percentage was located in the high-reserve, high-production portion of the pool. The initial 7-day shut-in pressures from new wells were then compared to the 7-day 1976 annual pressures taken from the four old wells immediately offsetting each infill well. A weighted average pressure for the 320-ac tract was then calculated for each township using those pressure relationships. The percentage increase from the average 1976 annual shut-in pressure of the old wells to the new tract weighted pressure was then determined and plotted on pool maps.

Using this information, a percentage factor increase for each township was estimated. This percentage factor was then applied to the reserve previously estimated to be recoverable under 320-ac well density in each township. The percentage increase figure varied from 33-120 percent depending upon the location of the acreage. As would be expected, infill wells located in the central portion of the pool, where reserves are larger and well-production rates are higher, invariably have the lowest percentage increase. Infill wells drilled toward the margin of the pool, where sand permeabilities are lower, invariably have higher pressures than do centrally located infill wells. In some edge areas the infill wells have essentially virgin reservoir pressure, indicating very little drainage of the 160-ac infill tract.

Unfortunately, these are also the portions of the pool that have the smallest recoverable reserve so that additions to total pool reserves are small from such areas. The percentage increase factors were then applied to the separate township reserve volumes previously calculated for each of the 57 townships in the pool. These volumes were then added, and the total pool adjustment was determined to be 2,097 billion cu ft. When added to the 4,223 billion cu ft recoverable reserve that was estimated for 320-ac drilling density, the recoverable reserve for 160-ac well density in the presently developed portion of the Blanco Mesaverde Pool becomes 6,320 billion cu ft. This estimate does not include any gas reserves contained in the Colorado portion of the pool. A tabulation of reserve information is shown in table 11.

RESERVE ESTIMATE—UNDEVELOPED PORTION OF THE POOL—The pool reserve contour map was used in conjunction with the well cumulative production and completion data maps to determine which undeveloped tracts within the Blanco Mesaverde Pool boundary contain economically recoverable gas reserves. There are approximately 694 undeveloped 320-ac tracts within the pool. Of these, 73 were removed from consideration on the basis of probable lack of sufficient producing capacity to return drilling investment within a reasonable time. Reserves were then estimated for the 621 remaining 320-ac tracts from the pool reserve contour map. The estimate is 520 billion cu ft, presuming 320-ac well density. The increase in the recoverable reserve that would result from 160-ac well density was estimated in the same manner as in the developed portion of the pool. This entailed assigning a percentage increase factor for each township based upon information developed from comparing shut-in pressures from infill wells and from their offsets in various portions of the pool. The estimated recoverable reserve for 320-ac well density was then adjusted by the appropriate percentage increase factor. The increase was approximately 280 billion cu ft, bringing the total remaining reserve to 800 billion cu ft for the undeveloped portion of the pool (table 12).

Additional infill drilling is now proceeding at a steady rate. Although most of the earlier drilling was confined to more productive portions of the pool, drilling activity is now increasing in portions of average and low production. Infill gas now sells at prices in excess of $1.50 per thousand cu ft; this price will most likely be sufficiently high to bring on infill development of the larger portion of the pool. Because of the extremely low productive capacity of wells drilled in marginal portions of the pool, there are still large undeveloped areas that cannot be drilled until gas prices are in excess of $2.00 per thousand cu ft.

TABLE 11—BLANCO MESAVERDE GAS POOL RECOVERABLE RESERVE ANALYSIS (developed acreage only).

Township-Range	Wells	Reserve (billion cu ft) (1)	(2)	(3)	(4)	(5)	(6)
26N-R2W	5	9.1	6.2	2.9	120	3.5	6.4
26N-R3W	31	43.0	24.1	18.9	120	22.7	41.6
26N-R4W	24	23.4	8.9	14.5	120	17.4	31.9
26N-R5W	27	51.8	21.1	30.7	60	18.4	49.1
26N-R6W	6	4.3	2.3	2.0	120	2.4	4.4
26N-R7W	8	5.9	2.9	3.0	120	3.6	6.6
26N-R8W	3	5.4	2.5	2.9	85	2.5	5.4
26N-R9W	3	12.4	7.1	5.3	65	3.4	8.7
27N-R3W	22	36.1	24.6	11.5	120	13.8	25.3
27N-R4W	29	30.2	13.4	16.8	120	20.2	37.0
27N-R5W	65	84.5	43.6	40.9	80	32.7	73.6
27N-R6W	65	127.1	64.0	63.1	85	53.6	116.7
27N-R7W	35	43.2	23.8	19.4	80	15.5	34.9
27N-R8W	64	119.5	47.0	72.5	85	61.6	134.1
27N-R9W	31	63.0	32.3	30.7	85	26.1	56.8
28N-R3W	5	3.9	.9	3.0	120	3.6	6.6
28N-R4W	18	13.6	7.3	6.3	120	7.6	13.9
28N-R5W	52	110.8	43.2	67.6	60	40.6	108.2
28N-R6W	54	224.5	90.2	134.3	50	67.2	201.5
28N-R7W	54	123.3	59.4	63.9	60	38.3	102.2
28N-R8W	54	145.0	70.7	74.3	55	40.9	115.2
28N-R9W	44	71.0	38.5	32.5	100	32.5	65.0
28N-R10W	1	.2	.1	.1	120	.1	.2
29N-R4W	5	.4	.2	.2	120	.2	.4
29N-R5W	45	175.0	67.7	107.3	50	53.7	161.0
29N-R6W	72	359.2	135.1	224.1	50	112.1	336.2
29N-R7W	71	254.7	126.4	128.3	55	70.6	198.9
29N-R8W	70	422.0	219.0	203.0	45	91.4	294.4
29N-R9W	69	305.1	173.9	131.2	50	65.6	196.8
29N-R10W	16	13.7	6.0	7.7	120	9.2	16.9
30N-R4W	3	2.4	1.4	1.0	120	1.2	2.2
30N-R5W	32	47.1	21.3	25.8	120	31.0	56.8
30N-R6W	68	281.1	131.6	149.5	55	82.2	231.7
30N-R7W	69	452.8	217.4	235.4	40	94.2	329.6
30N-R8W	70	672.8	342.7	330.1	33	108.9	439.0
30N-R9W	71	782.1	414.1	368.0	33	121.4	489.4
30N-R10W	62	178.6	92.2	86.4	75	64.8	151.2
30N-R11W	12	12.8	7.0	5.8	120	7.0	12.8
30N-R12W	4	2.3	1.3	1.0	120	1.2	2.2
31N-R5W	8	6.4	3.3	3.1	120	3.7	6.8
31N-R6W	24	19.7	9.8	9.9	120	11.9	21.8
31N-R7W	28	46.3	24.4	21.9	80	17.5	39.4
31N-R8W	55	208.7	117.2	91.5	40	36.6	128.1
31N-R9W	69	604.2	299.2	305.0	33	100.7	405.7
31N-R10W	71	624.7	291.2	333.5	33	110.1	443.6
31N-R11W	70	277.7	126.7	151.0	40	60.4	211.4
31N-R12W	62	147.8	78.8	69.0	49	33.8	102.8
31N-R13W	12	12.4	5.4	7.0	100	7.0	14.0
32N-R5W	5	3.6	1.6	2.0	120	2.4	4.4
32N-R6W	18	20.2	10.8	9.4	120	11.3	20.7
32N-R7W	24	46.9	20.7	26.2	80	21.0	47.2
32N-R8W	15	9.1	3.5	5.6	120	6.7	12.3
32N-R9W	28	39.9	17.6	22.3	90	20.1	42.4
32N-R10W	55	273.7	117.3	156.4	33	51.6	208.0
32N-R11W	54	370.4	163.4	207.0	45	93.2	300.2
32N-R12W	46	128.7	55.1	73.6	80	58.9	132.5
32N-R13W	8	12.1	5.7	6.4	100	6.4	12.8
Total	2,091	8,165.8	3,943.1	4,222.7		2,097.0	6,320.0

(1) Township original reserve, 320-acre density
(2) Township cumulative production, 12-31-74
(3) Remaining reserve corrected for stabilization, 320-acre density
(4) Estimated percent increase per Township for infill
(5) Infill adjustment to reserve for Township
(6) Township remaining recoverable reserve for 160-acre density

As additional production and pressure information becomes available from infill wells and as the long range effect of infill well production on old well production rates becomes more apparent, it will be possible to further refine recoverable reserve estimates. The volume of gas shown as "infill adjustment" should therefore be regarded as a preliminary estimate, subject to future correction.

Gas reserve comparisons, northwest New Mexico

Fig. 5 was constructed to depict the rather wide variations in gas reserve estimates published by different agencies. In part these variations are due to differences in parameters considered in each study; examples are the relative weight given to increases in recovery from infill drilling and adjustments made for the lack of pressure stabilization. For both geological and engineering reasons, investigators commonly arrive at different conclusions when estimating gas recovery from low permeability reservoirs such as those producing in the San Juan Basin. Geological reasons for these differences include: difficulty in determining porosity cutoff points so that net pay sand can be accurately identified, difficulty in determining effective permeability and water saturation, and difficulty in predicting lateral variations in reservoir quality. The lack of core data in many pools adds to the difficulty in accurately assessing recoverable reserves. Engineering aspects leading to differences in

TABLE 12—ESTIMATED GAS RESERVE FOR NEW MEXICO PORTION OF BLANCO MESAVERDE GAS POOL AS OF DECEMBER 31, 1974.

	Reserve (billion cu ft)	
	320-acre well density	160-acre well density
Developed Portion	4,223	6,320
Undeveloped Portion	520	800
Total	4,743	7,120

reservoir interpretation include: lack of pressure stabilization, which makes it difficult to determine the actual reservoir pressure under a tract; loading problems in wells from both water and liquid hydrocarbons produced with the gas; and low production rates in some areas, which aggravate the liquid loading problem.

Recoverable reserves must also be adjusted to reflect changes caused by economic factors such as changes in the wellhead price of natural gas; these price increases expand that portion of marginal production areas which can be drilled at a profit and extend the producing life of wells near depletion.

The gas reserve estimates of API and FEA are discussed elsewhere in this report. The bar graph on the far right (fig. 5) shows the reserve estimate given by the Office of the State Geologist for northwest New Mexico; at the moment, this estimate is tentative, because the amount of gas shown in "other pools" is still under study. Preliminary studies have been completed in the Blanco Mesaverde and Basin Dakota Pools, and these estimates will be subject to possible revision as additional information from infill drilling becomes available. The estimate does include the amount of additional gas thought at this time to be recoverable by drilling to 160-ac density in the Blanco Mesaverde Pool and also includes proven reserves in undeveloped portions of the pool.

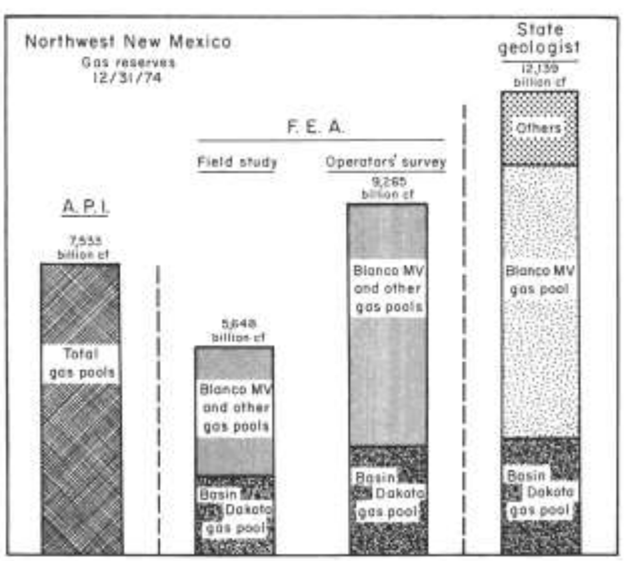

FIGURE 5—COMPARISON OF ESTIMATED GAS RESERVES IN NORTHWEST NEW MEXICO AS OF DECEMBER 31, 1974 (sources: API and FEA).

Wagon Mound Dakota-Morrison gas field

The first commercially producible dry gas discovered in northeast New Mexico is located in the Las Vegas subbasin, with production coming from the Cretaceous Dakota Sandstone. Following the wildcat discovery well in September 1973 by Brooks Exploration Inc., and subsequent to the openhole completion of five additional wells, the NMOCC established the Wagon Mound Dakota-Morrison Gas Pool. This field is located near the town of Wagon Mound and centered in sec. 14, T. 21 N., R. 21 E., Mora County (fig. 6). Although the full extent of the gas field is undetermined at this time, and the total addition to New Mexico gas reserves will probably be insignificant, its location creates new interest in exploration in northeast New Mexico. The pool is unusually interesting because of the unique low formation pressures, which average around 5 psi. Low drilling costs, which result from shallow producing depths, have offset the marginal production rates and have made development of the field feasible. Improved gas prices have contributed to additional exploration in this and other unexplored areas in the state. The area of the Las Vegas subbasin was designated as a favorable area for oil and gas exploration on the basis of sedimentary rock thicknesses in excess of 9,000 ft, the presence of possible source rocks, and the presence of good reservoir rocks (Foster and Grant, 1974).

Production

First commercial production in the field was reported in July 1976, and the cumulative production as of July 1977 was over 55 million cu ft. The gas is being produced from the Dakota and Morrison Sandstones, which are encountered at depths from 400-800 ft. The thickness of the producing zone varies from 78-141 ft. There is no water produced from this interval. Four wells are currently producing, and the other two wells are shut in awaiting further economic evaluation (B. Brooks, personal communication). The total average daily production from the four wells is 300-500 thousand cu ft. Difficulties in marketing the low-pressure

FIGURE 6—WAGON MOUND, NEW MEXICO, LOCATION MAP.

gas have arisen because multi-stage compression is necessary for injection into the high-pressure pipeline for sales of gas to Las Vegas (B. Brooks, personal communication). Artificial fracturing, induced by exploding nitroglycerin, was used to stimulate production in most of the wells. Bottom-hole pressures have decreased by 50 percent from the initial pressure, but are now leveling off (B. Brooks, personal communication). Engineers are monitoring pressures in order to assess the proven reserves and predict future production.

Geologic setting

The Wagon Mound Dakota-Morrison gas field is located in the Las Vegas subbasin, a Tertiary geologic feature. The existence of an earlier basin, the Paleozoic Rowe-Mora Basin, is recorded by a thick Pennsylvanian section. The Rowe-Mora Basin was an intervening depositional area between the San Luis, Wet Mountain, Apishapa, and Sierra Grande uplifts during Paleozoic time (fig. 7). After the uplifts were reduced by erosion, the area was covered by sediments ranging in age from Permian through Jurassic (Baltz, 1965; McGookey and others, 1972). The uplifts were rejuvenated during Early Cretaceous time (fig. 8) and are believed to be the source area for the braided alluvial interval of the Dakota Sandstone (Baltz, 1965; McGookey and others, 1972). Paleocurrent, grain-size, and sedimentary structure analyses indicate that the source areas were the San Luis and Apishapa uplifts (Gilbert and Asquith, 1976). This area was then inundated by the Late Cretaceous sea that extended over much of the western interior of the United States. The major tectonic elements that existed during Early and Middle Tertiary time in northeast New Mexico were the Sangre de Cristo Mountains, the Raton Basin, the Las Vegas subbasin, the Wet Mountains, the Apishapa uplift, and the Sierra Grande arches (fig. 9). These Tertiary features have continued to exist to the present as the main structures of the area.

Stratigraphy and structure

The stratigraphic column in the Las Vegas subbasin includes Pennsylvanian through Cretaceous rocks and exceeds 9,000 ft in thickness. The section includes both marine and continental sediments. The Cretaceous rocks are unconformably overlain by Quaternary alluvium, gravels, conglomerates, and basalts. Because the gas discovery was made in the Dakota Sandstone, only stratigraphy of the Dakota Sandstone and adjacent strata will be dealt with here.

The lower contact of the Dakota Sandstone is transitional and unconformable with the fluvial meander-belt sequence of the Upper Morrison Formation. The Morrison grades upward from fine- to medium-grained quartzose sand, which was deposited in broad floodplains and river channels, into the coarser grained braided alluvial sheet of the Dakota Sandstone. The Dakota is conformably overlain by the marine Cretaceous Graneros Shale. The Dakota was subdivided (Jacka and Brand, 1972) into a braided alluvial interval, a middle meander-belt interval, and an upper transgressive marine sandstone interval. The cleaner, better sorted sand intervals in these units comprise the gas reservoir in this area. Drilling has indicated porosities averaging 15

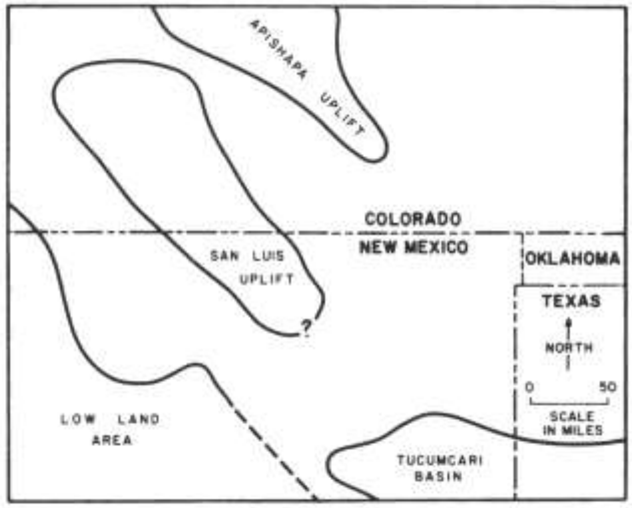

FIGURE 8—EARLY CRETACEOUS UPLIFTS AND BASINS IN NEW MEXICO AND COLORADO (modified after McGookey and others, 1972).

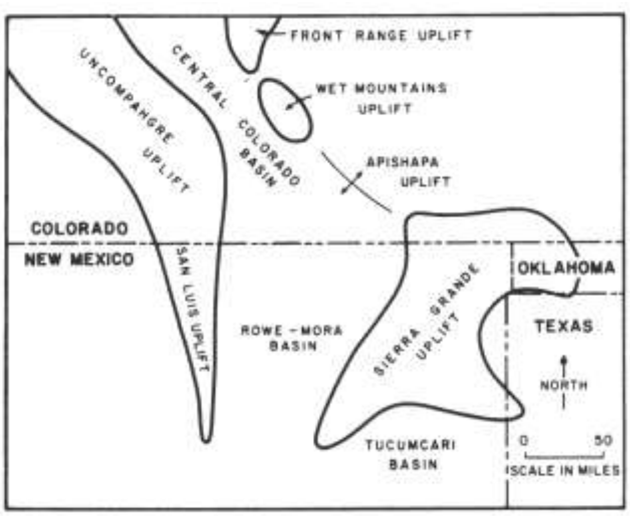

FIGURE 7—LATE PALEOZOIC UPLIFTS AND BASINS IN NEW MEXICO AND COLORADO (source: Gilbert and Asquith, 1976).

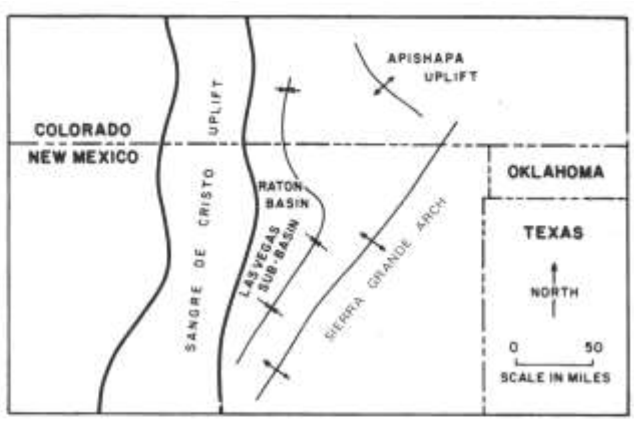

FIGURE 9—EARLY AND MIDDLE TERTIARY UPLIFTS AND BASINS IN NEW MEXICO AND COLORADO (modified after Baltz, 1965).

percent and excellent permeabilities averaging about two darcies in these sandstone intervals.

The trap that encompasses the Wagon Mound Gas Pool is a northwest-southeast-trending anticlinal fold. The structure is believed to be caused by draping over block faulting associated with the Sierra Grande uplift (B. Brooks, personal communication). The estimated area of the anticline is approximately 5,000 acres, and it has a closure of about 200 ft.

Future exploration

Exploration in the area is expected to continue with the primary target being the Dakota and Morrison Sandstones, although production possibilities exist in other zones such as the Entrada (Exeter) Sandstone. The limited number of completed wells drilled in Mora County (table 13) demonstrates that much of the Las Vegas subbasin is relatively unexplored. Additional subsurface data is needed to reconstruct the paleoenvironments and to evaluate the oil and gas potential of the area.

Graphic sections compiled by Northrop and others (1946) and Bachman (1953) show thick sections of Pennsylvanian bituminous shales, which would provide a source for hydrocarbons, as well as for porous sandstone, to provide reservoir rocks. These sections also show an eastward thinning of the thick Pennsylvanian sequence from the thrust belt area on the western edge of the basin to a wedge edge on the east boundary, the Sierra Grande arch.

Facies changes accompanying this thinning may have provided stratigraphic traps for accumulation of hydrocarbons. Structural traps may also be present. Outcrops in much of the area are obscured by Quaternary alluvium, gravels, and basalt flows, so that evidence of structural or stratigraphic traps will have to be obtained from subsurface data from drilling or geophysical surveys.

TABLE 13—COMPLETED WELLS DRILLED IN MORA COUNTY, NEW MEXICO TO JULY 1977 (source: NMOCC).

Well	Location Sec., Twp., Rge.	Lease holder
A. McArthur #1E	12, T.19N., R.21E.	Shamrock Oil & Gas Corp.
Ft. Union 1-0	2, T.20N.,R.19E.	Union Land Grazing Co.
Clyde Berlier #1a-N	14, T.21N., R.21E.	Brooks Exploration, Inc.
Clyde Berlier #2-A	23, T.21N., R.21E.	Brooks Exploration, Inc.
Clyde Berlier #3-A	22, T.21N., R.21E.	Brooks Exploration, Inc.
Clyde Berlier #4-M	23, T.21N., R.21E.	Brooks Exploration, Inc.
Gonzales-Pittman #1-M	24, T.21N., R.21E.	Service Drilling Co.
Mora Ranch #1-P	5, T.22N., R.19E.	Shell Oil Company
Mares-Duran #1-L	14, T.23N., R.17E.	Continental Oil Co.
Jeoffroy #1-M	21, T.23N., R.22E.	Filkey
Rinehart #1-M	29, T.23N., R.22E.	Trio Oil Co.
Rinehart #2-M	29, T.23N., R.22E.	Trio Oil Co, or Willard Franks
Jeoffroy #1-C	32, T.23N., R.22E.	Feanks & Hesser
Shell State #1-L	35, T.23N., R.22E	Shell Oil Co.

Remaining reserves for 30 oil pools in southeast area containing 75 percent of secondary recovery projects

In 1976 the Office of the State Geologist initiated a primary and secondary oil reserve study of 30 pools in southeast New Mexico. These 30 pools are among the 50 largest producing pools in the area and contain 75 percent of the secondary recovery projects.

Statistical data pertaining to the annual primary and secondary oil production from the 30 pools were compiled from several sources, including the NMOCC, the New Mexico Oil and Gas Engineering Committee, and numerous oil companies. Additional information was assembled, such as the number of acres in each pool, the waterflood acreage as defined by the NMOCC, the location of water injection wells, and the production history in each of the waterflood projects. Production decline curves were also prepared for use in the study.

Early in 1977 the consulting engineering firm of Sipes Williamson, and Aycock, Inc., of Midland, Texas, was placed under contract to evaluate the above data to determine remaining primary and/or secondary oil reserves for the 30 pools. The evaluation was based upon the extrapolation of the historical oil production decline trends exhibited by either the total pool or various waterflood units within the pool. The log of monthly oil production versus time was plotted. The historical oil production graph for most of the pools did not provide a consistent production decline trend from which extrapolation could be made to determine either remaining primary and/or secondary oil reserves. The pool production graph was generally affected by additional drilling; the timing, number, and production response of secondary recovery projects; and the changing of allowable structures. In most cases the pool production graph was affected most drastically by the response to secondary recovery operations from various units within the pool. For this reason, in a majority of the cases, it was necessary to plot the historical oil production for each unit within the pool. The unit areas were outlined on pool maps by using a combination of unit outlines indicated in the public record and from NMOCC records. In many cases conflicts existed between data sources as to the outlines of these various units; generally, however, these differences were resolved satisfactorily. The earliest year oil production figures were available for each of the pools was 1940.

One or a combination of the following three procedures was utilized to determine the primary and secondary oil ultimate recoveries for each pool. By subtracting cumulative production as of January 1, 1977, reserves as of that date were established.

Approach No. 1 was used if the historical oil production graph for the pool allowed extrapolation of the primary production trend to an estimated economic limit, thus allowing determination of the primary oil ultimate. In those cases where essentially the total pool area is under secondary recovery operations and recent production is declining, an extrapolation can be made to an estimated economic producing limit, which yields the total ultimate oil recovery figure for the pool, including both primary and secondary oil ultimates. The secondary ultimate can thus be determined by subtracting the primary ultimate from total ultimate. The remaining reserves were calculated by subtracting cumulative production as of January 1, 1977, from the total ultimate value.

When the pool's historical oil production could not be extrapolated with any degree of certainty, approach No. 2 was used to determine the primary and secondary ultimates by water flood unit basis within the pool. If the majority of the pool was under secondary recovery operations, then most of the secondary recovery project production from the date of unitization was subtracted from the total pool production to yield a residual primary production graph. If a decline trend was observed, an extrapolation could be made to determine the primary ultimate for the pool. In some cases, plots of the percent water in total fluid versus cumulative oil production would yield a trend that could be extrapolated to an expected ultimate recovery.

Approach No. 3 was used as a variation to approach No. 2 in cases where only a small part of the pool area was under secondary recovery operations. The available secondary recovery units were analyzed to determine primary and secondary ultimate recoveries, and a ratio between the two was established. The secondary to primary recovery ratio was then applied to the primary ultimate for the entire pool where such primary ultimate could be determined from the production history.

Many methods were utilized in normalizing the production trends to obtain data from which reliable extrapolation could be made. Where substantial drilling had occurred, total production was divided by total number of wells to arrive at a per well production graph. There were some cases where the primary production trend, either for the total pool or as a residual curve after waterflood unit production had been subtracted, failed to yield a production decline trend that could be extrapolated. In these cases, individual lease production curves were plotted, which did yield a production decline trend that could be extrapolated to calculate the primary ultimate recovery for the lease. The acreage that was drained from these individual leases was determined by a method devised by J. J. Arps and T. G. Roberts (1955). The primary recoveries by lease over the pool area were averaged and then applied to the total pool primary ultimate.

The results of the Sipes, Williamson, and Aycock, Inc. evaluation of remaining primary and secondary oil reserves show the 30 pools to have had a cumulative production of 1.806 billion barrels as of January 1, 1977. The reserve study also indicates a primary ultimate recovery of 1.807 billion barrels, a secondary ultimate recovery of 660 million barrels, and a remaining reserve of 661 million barrels. These 30 pools contain over 900 thousand ac. By applying the acreage participation formula of the NMOCC (Rule 701) to the waterflood projects within these pools, we can determine that approximately one-third of the pool acreage has been flooded or is currently being flooded.

The reliability of several of the oil reserve estimates in the Sipes, Williamson, and Aycock, Inc. reserve evaluation can be greatly improved by a further geological and engineering study of various pools. Particular pools that need further study are the large pools that contain only one or two secondary recovery projects. The secondary to primary recovery factor derived from performance of current projects could change considerably in portions of the reservoir that have not yet been placed under secondary recovery, thus changing the remaining reserve estimates substantially. Pools producing from more than one formation and containing numerous small secondary recovery projects that are now in progress need further study because of the difficulty in evaluating secondary recovery results. The reliability of estimates of secondary reserves is very important because the Sipes, Williamson, and Aycock, Inc. reserve evaluation indicates that of the estimated 661 million bbls remaining in these 30 pools, only 146 million bbls are recoverable by primary methods.

Oil pool reserve studies

Over the past year and a half, the Office of the State Geologist and the New Mexico Bureau of Mines and Mineral Resources have conducted a program to evaluate the oil reserves of New Mexico. This report summarizes the current results of that investigation. The primary intent has been to estimate eventually the reserves for each oil pool in the state. As an initial step, two pilot programs have been conducted. The first, conducted by the Bureau of Mines, was to estimate the reserves of the 50 largest pools. The second was to evaluate the reserves of 30 of these pools in which enhanced recovery programs have been initiated so that a more accurate estimate of future enhanced recovery reserves may be made. The second study was initiated by the Office of the State Geologist and supplemented by Sipes, Williamson, and Aycock, Inc., a consulting firm under contract to the Office of the State Geologist. Twenty-

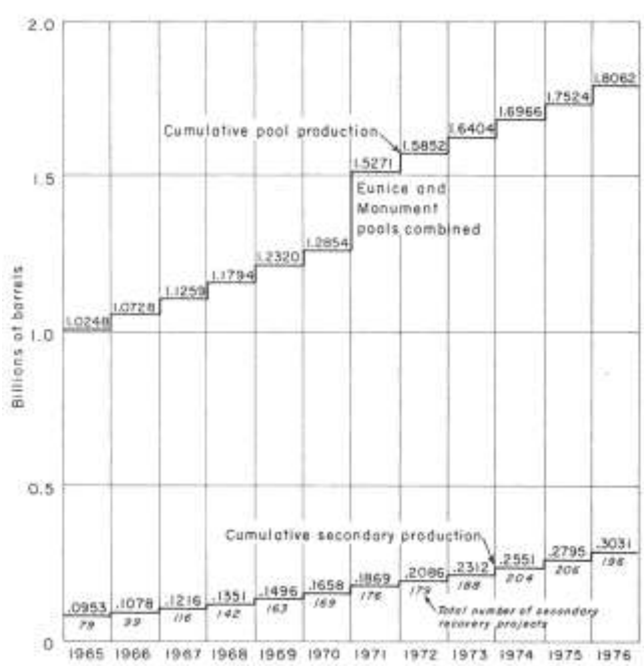

FIGURE 10—CUMULATIVE PRODUCTION FROM THE 30 POOLS CONTAINING 75 PERCENT OF THE SECONDARY RECOVERY PROJECTS IN SOUTHEAST NEW MEXICO (sources: NMOCC and New Mexico Oil and Gas Engineering Committee).

nine of these pools were among the 50 evaluated at the New Mexico Bureau of Mines and Mineral Resources.

Selection of the 50 pools was based on the amount of oil produced in 1975. In that year there were 505 designated oil pools containing 13,580 wells with reported production of oil. Of these, 50 accounted for 80 percent of the total crude oil produced in New Mexico, and the three largest (Empire Abo, Vacuum Grayburg-San Andres, and Maljamar Grayburg-San Andres) accounted for 29 percent.

Three methods were used to estimate the amount of remaining recoverable oil in the 50 pools examined in this study:

1) Reservoir evaluation—In 49 pools, the method of calculating reserves was based on the rate of decline of oil produced during the base period. The only pool for which some variation of this method could not be used was Empire Abo. In this case reserve estimates were from exhibits presented to the NMOCC. The evaluation was based on estimates of the original oil in place, the remaining oil, and the economic life.

2) A multiple regression program (35 pools) and an equivalent exponential curve fit (6 pools) using current production data—The computer program used in this study was a special version of a rather general multiple regression routine. This routine relies heavily on subroutines that are in the IBM Scientific Subroutine Package. The program will be simplified so that it can be used on other computers. The reason for originally using a rather general multiple regression routine was that it permitted experimentation with several different prediction models. The final model used was a simple regression of the logarithm of production versus time. In the final projections the conversion back to non-logarithmic data was carried out, and an approximate 95 percent confidence interval was computed for each predicted value. This prediction interval gives some idea of the precision of the predicted value, provided that the original model was correct.

Input data was from the peak average daily production per month for the 1975-1976 base period. This period was used so that only current developments would be reflected in production projections for the state.

Using the same input data, the logarithmic curve fit procedure described above can be accomplished with a programmable pocket calculator. For this report the HP-25C calculator, along with the program for exponential curve fitting from the Hewlett-Packard applications program manual, was used. The results are essentially the same as those obtained with the multiple regression routine, with minor variations due to round-off differences.

A comparison of projections obtained by the multiple regression program and exponential curve fit is given in table 14 for the Hobbs Blinebry Pool. Also shown on this table are estimates for future production, using the constant percentage decline method. This method is commonly used by engineers when cumulative production and rate of production plotted on Cartesian paper result in a straight line relationship. The data base in all three cases is the average daily production for the period from September 1975 through October 1976. Projected production is nearly equivalent using either the multiple regression or exponential curve fit. These two methods

TABLE 14—COMPARISON OF DECLINE-CURVE METHODS: HOBBS-BLINEBRY POOL (economic limit 39,420 bbls of oil).

	Bbls of oil		
Year	Multiple regression	Exponential curve fit	Constant % decline
1977	296,563	296,457	287,665
1978	245,463	245,503	223,635
1979	203,305	203,306	177,326
1980	168,909	168,824	140,605
1981	139,430	139,425	111,489
1982	115,523	115,461	88,403
1983	95,630	95,616	70,096
1984	79,422	79,399	55,581
1985	65,518	65,572	44,072
1986	54,385	54,302	34,945
1987	44,895	44,969	
1988	37,332	37,342	
Reserves	1,546,375	1,546,176	1,233,817
Decline rate	17%	17%	11%

indicate an economic life of 12 years and recoverable reserves of 1.5 million bbls of oil after January 1, 1977. From the constant percentage decline method, the economic life is 10 years and the reserve 1.2 million bbls of oil.

3) Historic decline rates taken from periods of stable pool conditions (8 pools)—This method was used to project production where it was increasing during the 1975-1976 base period or where the peak daily production occurred near the end of this period. The decline rate used was from a stable period during the history of the pool under either primary or secondary recovery. If waterflooding or other enhanced recovery programs were not involved or were initiated near the end of the base period, a primary decline rate was used. If stable pool conditions were present following the start of an enhanced recovery program, a secondary decline rate was used. In both cases the percentage used was the average yearly decline for the stable period. Future production was calculated at this rate of decline from January 1, 1977.

An example of the use of a historic rate of decline is given for the Chaveroo San Andres Pool (fig. 11). This pool was discovered in 1965. Peak production was reached two years later at 4.2 million bbls of oil from 345 wells. For the 1975-1976 base period, the highest production was 1,717 BOPD (bbls of oil per day) in December 1976. Waterflooding initiated in 1968 involves only a small portion of the pool, accounting for slightly over six percent of the 1975 production. The in-

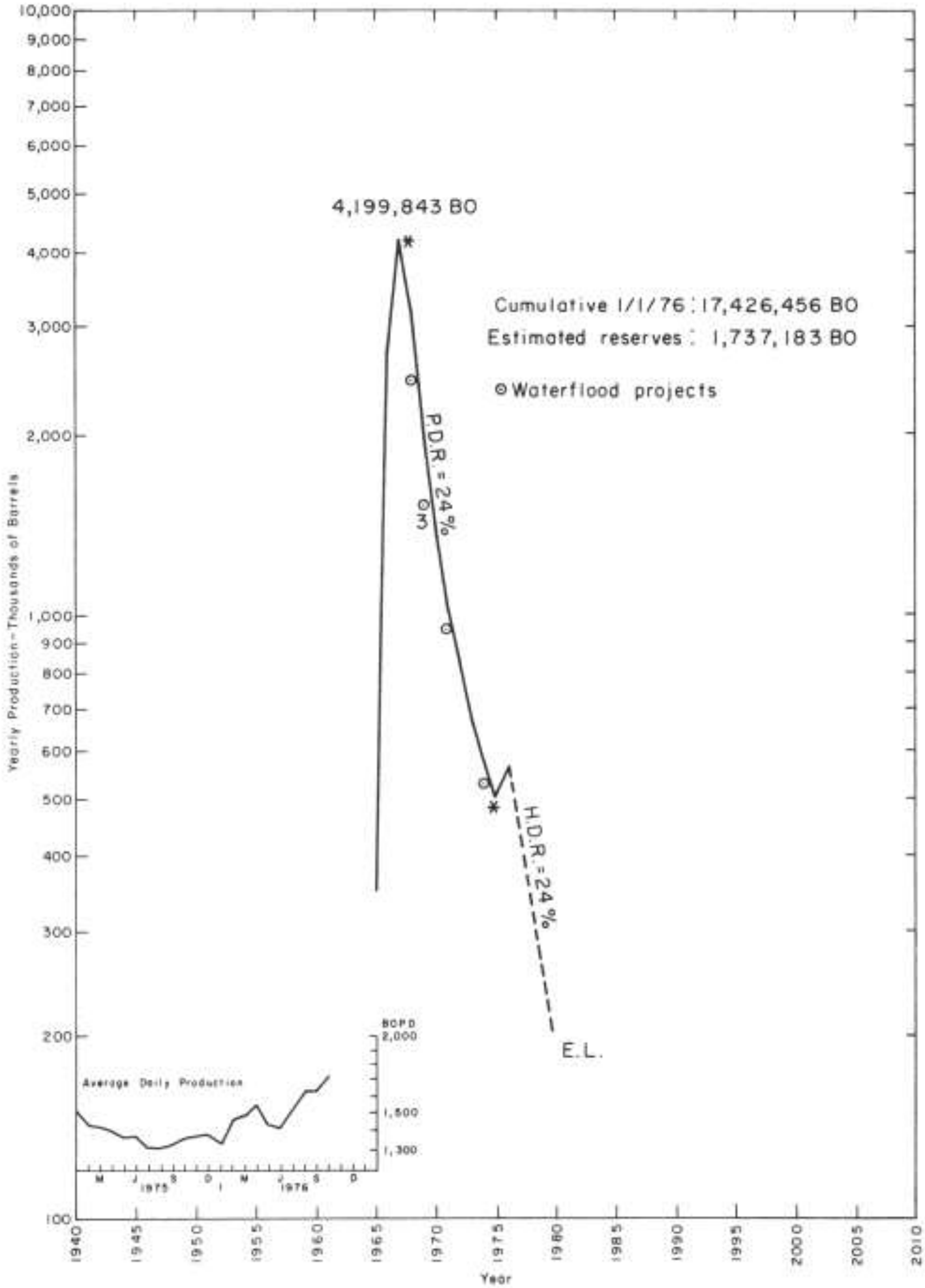

FIGURE 11—CHAVEROO-SAN ANDRES PRODUCTION DECLINE CURVE.

crease in production for 1976 is the result of additional well completions. Using the decline of 24 percent per year from the stable period from 1967-1975, the indicated reserves are 1.7 million bbls of oil.

At some stage in the life of an oil well, continued production of oil remaining in the reservoir is no longer economically feasible. This point can occur rather abruptly where a natural water drive or a gas cap is the source of reservoir energy. In most cases near the end of the life of a well, the amount of oil produced will slowly decline to a point where the cost of moving the oil to the surface ("life costs") exceeds the value of the produced oil. In order to determine the economic limit for this study, an analysis of each of the 505 active oil pools in New Mexico was made for 1975. Results of this study are summarized in table 15. The data indicate that depth can be used only in a general way. Because of this only two classifications were used: an economic limit of 2 bbls of oil per day per well at depths shallower than 5,000 ft, and 4 bbls of oil per day below 5,000 ft.

Economic limits in barrels of oil per year for a specific pool can seem quite high. An example is the Vacuum Grayburg-San Andres Pool. Based on 2 bbls of oil per day per producing well at the beginning of 1976 and on 449 producing wells, the economic limit would be 327,770 bbls of oil. However, if this amount of oil were produced each year for a period of 10 years after the economic limit was reached, the net change in the estimated ultimate recovery for this pool would be only one percent.

TABLE 15—1975 OIL WELL PRODUCTION DATA AND CLASSIFICATION BY DEPTH (BOPY = Average annual production per well; BOPD = Average daily production per well).

Depth Range	> 10 BOPD					< 10 BOPD (Strippers)					All Pools				
	1975 Prod. (%)	Pools	Wells	BOPY	BOPD	1975 Prod. (%)	Pools	Wells	BOPY	BOPD	1975 Prod.	Pools	Wells	BOPY	BOPD
Southeast Area															
0-5,000'	28,245,713 (75)	43	3,801	7,431	20.1	9,629,176 (25)	134	4,503	2,138	5.9	37,874,889	177	8,304	4,561	12.5
5,000-6,000'	5,806,930 (81)	21	612	9,488	26.0	1,402,680 (19)	11	636	2,205	6.0	7,209,610	32	1,248	5,777	15.8
6,000-7,000'	16,157,539 (90)	12	349	46,297	126.8	1,788,120 (10)	13	731	2,446	6.7	17,945,659	25	1,080	16,616	45.5
7,000-8,000'	1,335,592 (85)	20	156	8,561	23.5	234,587 (15)	11	85	2,760	7.6	1,570,179	31	241	6,515	17.9
8,000-9,000'	5,432,933 (99)	17	270	20,122	55.1	67,941 (1)	9	28	2,426	6.7	5,500,874	26	298	18,459	50.6
9,000-10,000'	8,186,685 (99)	41	858	9,542	26.1	73,572 (1)	10	30	2,452	6.7	8,260,257	51	888	9,302	25.5
10,000-11,000'	2,368,662 (95)	36	179	13,233	36.3	111,671 (5)	11	44	2,538	7.0	2,480,333	47	223	11,123	30.5
11,000-12,000'	2,767,422 (99)	22	161	17,189	47.1	17,018 (1)	10	10	1,702	4.7	2,784,440	32	171	16,283	44.6
12,000-13,000'	2,263,323 (>99)	15	83	27,269	74.7	532 (<1)	1	1	532	1.5	2,263,855	16	84	26,951	73.8
>13,000'	232,929 (99)	4	15	15,529	42.5	2,657 (1)	1	1	2,657	7.3	235,586	5	16	14,724	40.3
Subtotal >5,000'	44,552,015 (92)	188	2,683	16,605	45.5	3,698,778 (8)	77	1,566	2,362	6.5	48,250,793	265	4,249	11,356	31.1
All Pools	72,797,728 (85)	231	6,484	11,227	30.8	13,327,954 (15)	211	6,069	2,196	6.0	86,125,682	442	12,553	6,861	18.8
Northwest Area															
0-5,000'	1,497,256 (62)	10	280	5,347	14.7	929,903 (38)	29	377	2,467	6.8	2,427,159	39	657	3,694	10.1
5,000-6,000'	449,687 (73)	7	92	4,888	13.4	168,778 (27)	7	136	1,241	3.4	618,465	14	228	2,713	7.4
>6,000'	1,105,172 (88)	1	51	21,670	59.4	152,134 (12)	9	91	1,672	4.6	1,257,306	10	142	8,854	24.3
Subtotal >5,000'	1,554,859 (83)	8	143	10,873	29.8	320,912 (17)	16	227	1,414	3.9	1,875,771	24	370	5,070	13.9
All Pools	3,052,115 (71)	18	423	7,215	19.8	1,250,815 (29)	45	604	2,071	5.7	4,302,930	63	1,027	4,190	11.5
State Totals															
<5,000'	29,742,969 (74)	53	4,081	7,288	20.0	10,559,079 (26)	163	4,880	2,164	5.9	40,302,048	216	8,961	4,497	12.3
>5,000'	46,106,874 (92)	196	2,826	16,315	44.7	4,019,690 (8)	93	1,793	2,242	6.1	50,126,564	289	4,619	10,852	29.7
All Pools	75,849,843 (84)	249	6,907	10,982	30.1	14,578,769 (16)	256	6,673	2,185	6.0	90,428,612	505	13,580	6,659	18.2

Projected reserves for the 50 largest pools are given in table 16. Estimates given are based on the assumption that future conditions will remain the same as during the base period. However, petroleum exploration and development is generally dynamic even at the individual pool level and changes are to be expected. By using a computer program such as the multiple regression routine used for this report, new reserve estimates can be made rapidly and inexpensively as conditions change. As with the state prediction, production projections for individual pools will, in general, be reasonably accurate for short terms.

Ultimately it is hoped that reservoir evaluation studies will be conducted for each pool to arrive at a better reserve estimate and, beyond this, an estimate of the total oil resource for the state. To this end the computer program has recently been revised to include subroutines, printout simplification, curve-plotting capabilities, and extraction of pool and well production data from the magnetic tapes available for the 1969-1976 period. Yearly production data, including oil, gas, and water, as well as the number of producing wells, have been compiled for over 800 oil pools (including abandoned pools). This data should be keypunched before the end of the year. Other studies will involve material balance and sand-volume methods of reserve estimates and digitizing of geophysical logs to determine porosity, water saturation, and other qualities. Of immediate concern, particularly with the establishment of the Petroleum Recovery Research Center at the New Mexico Institute of Mining and Technology, is an in-depth study of each of the pools in the state that has active waterflood projects. A geologic report on the Loco Hills Pool (Foster, 1976), supported by the New Mexico Energy Resources Board, was released in December 1976. This report will serve as a guide for future studies. The full report on the 50 pools and the production projection for the state has been completed and should be available within a year as New Mexico Bureau of Mines and Mineral Resources Circular 166.

Oil pool reserve estimate comparison

Remaining pool reserves resulting from the study by Sipes, Williamson, and Aycock, Inc. and the Office of the State Geologist are shown in table 17 (column 1), compared with remaining pool reserves as determined by an oil reserve study conducted by the New Mexico Bureau of Mines and Mineral Resources and the Office of the State Geologist (column 2). Also shown are the percent difference between the two estimates and the percent of undeveloped secondary acreage in each of the pools. Results from both reserve studies are preliminary and will be revised when further geological and engineering studies are made.

A comparison of the two studies may be made by examining table 17. In many pools the Sipes, Williamson, and Aycock, Inc. estimate is substantially larger than that of the New Mexico Bureau of Mines. These differ-

TABLE 16—ESTIMATED RESERVES AND ULTIMATE RECOVERY OF 50 LARGEST OIL POOLS.

Rank 1/1/76	Field	Discovery Year	Depth Factor M=1,000 ft	Approximate Decline Rate	Recovery (bbls) to 1/1/76	Estimated Reserves (bbls)	Ultimate Recovery (bbls)	Remaining %
1	Empire Abo (1)	1957	6M-7M*	--	127,776,576	85,023,424	212,800,000	40%
2	Vacuum GB-SA (2)	1929	0-5M	5%	159,307,712	113,186,510	272,494,222	42%
3	Maljamar GB-SA (2)	1926	0-5M	12%	106,266,703	32,815,518	139,082,221	24%
4	Hobbs GB-SA (2)	1928	0-5M	14%	226,978,885	22,326,892	249,305,777	9%
5	Eunice-Monument GB-SA (3)	1929	0-5M	6%	320,986,627	49,288,145	370,274,772	13%
6	Langlie-Mattix Y-SR-Q (2)	1929	0-5M	12%	91,866,446	21,270,748	113,137,194	19%
7	Vacuum Abo Reef (2)	1960	8M-9M	24%	67,671,100	11,643,839	79,314,939	15%
8	Vacuum Glorieta (2)	1963	5M-6M	8%	38,784,478	32,049,781	70,834,259	45%
9	Bagley Penn, North (2)	1970	9M-10M	23%	37,819,611	8,490,139	46,309,750	18%
10	Grayburg-Jackson Q-GB-SA (2)	1929	0-5M	10%	74,349,934	14,460,611	88,810,545	16%
11	Drinkard (2)	1944	6M-7M	19%	69,691,580	6,243,611	75,935,191	8%
12	Vacuum Abo, North (4)	1963	9M-10M	8%	12,521,096	22,844,764	35,365,860	65%
13	Crossroads S-D (2)	1948	12M-13M	33%	37,166,001	2,824,177	39,990,178	7%
14	Vada Penn (2)	1967	9M-10M	26%	46,398,811	4,313,770	50,712,581	9%
15	Tocito Dome Penn D (2)	1964	6M-7M	54%	10,763,368	780,352	11,543,720	7%
16	Jalmat T-Y-SR (2)	1953	0-5M	12%	55,517,999	8,143,830	63,661,829	13%
17	Blinebry Oil and Gas (2)	1945	5M-6M	14%	34,883,919	3,181,451	38,065,370	8%
18	Justis Blinebry (2)	1958	5M-6M	25%	21,820,022	3,221,129	25,041,151	13%
19	Eumont Y-SR-Q (2)	1953	0-5M	12%	64,254,922	5,068,885	69,323,807	7%
20	Denton D (2)	1949	11M-12M	19%	90,150,236	3,704,554	93,854,790	4%
21	Shugart Y-SR-Q-GB (2)	1937	0-5M	9%	14,787,132	7,372,772	22,159,904	33%
22	Lovington Abo (2)	1952	8M-9M	9%	27,348,277	7,264,107	34,612,384	21%
23	Denton WC (2)	1950	9M-10M	16%	32,749,051	3,269,504	36,018,555	9%
24	Paduca Del (2)	1961	0-5M	11%	9,481,149	5,130,818	14,611,967	35%
25	Loco Hills Q-GB-SA (2)	1939	0-5M	37%	41,104,065	1,380,591	42,484,656	3%
26	Square Lake GB-SA (4)	1941	0-5M	7%	20,736,400	3,326,490	24,062,890	14%
27	Artesia Q-GB-SA (3)	1923	0-5M	14%	22,344,628	3,279,482	25,624,110	13%
28	Paddock (2)	1945	5M-6M	14%	21,902,480	2,838,741	24,741,221	11%
29	Chaveroo SA (4)	1965	0-5M	24%	17,426,456	1,737,183	19,163,639	9%
30	Wantz GW (4)	1963	7M-8M	15%	1,250,628	4,007,868	5,258,496	76%
31	Eunice SR-Q, South (4)	1930	0-5M	14%	23,088,739	4,691,510	27,780,249	17%
32	Horseshoe Gallup (4)	1956	0-5M	19%	34,613,623	2,018,992	36,632,615	6%
33	Corbin Abo (3)	1959	8M-9M	27%	11,754,684	1,544,907	13,299,591	12%
34	Hobbs Blinebry (2)	1968	5M-6M	17%	3,711,963	1,906,103	5,618,066	34%
35	Flying M SA (3)	1964	0-5M	10%	4,916,900	3,171,497	8,088,397	39%
36	Hospah Lower Sand, South (2)	1966	0-5M	10%	2,905,839	3,483,754	6,389,593	55%
37	Pearl Queen (2)	1956	0-5M	20%	17,661,300	1,469,988	19,131,288	8%
38	Bronco S-D (2)	1953	11M-12M	26%	13,093,519	1,155,322	14,248,841	8%
39	Bagley S-D (2)	1949	10M-11M	18%	24,967,415	1,496,389	26,463,804	6%
40	Dollarhide D (2)	1952	8M-9M	11%	5,437,079	2,764,944	8,202,023	34%
41	Dollarhide Tubb-Drinkard (3)	1951	6M-7M	20%	15,176,164	1,498,860	16,675,024	9%
42	Baum Upper Penn (2)	1955	9M-10M	5%	6,312,592	5,257,092	11,569,684	45%
43	Puerto Chiquito Mancos, West (2)	1966	0-5M	6%	5,456,384	4,979,324	10,435,708	48%
44	Moore D (3)	1952	10M-11M	17%	20,441,031	1,438,998	21,880,029	7%
45	Lovington Paddock (4)	1952	6M-7M	16%	11,474,369	1,538,467	13,012,836	12%
46	Penrose-Skelly GB (2)	1936	0-5M	21%	17,687,107	858,547	18,545,654	5%
47	Hospah Upper Sand, South (2)	1967	0-5M	25%	3,094,136	664,449	3,758,585	18%
48	Caprock Q (2)	1941	0-5M	16%	71,223,144	1,104,640	72,327,784	2%
49	Cato SA (4)	1966	0-5M	33%	13,339,347	635,506	13,974,853	5%
50	Sawyer SA, West (2)	1968	0-5M	14%	1,417,127	1,599,809	3,016,936	53%
			TOTALS		2,196,682,590	548,984,948	2,745,667,538	20%

(1) Projection from reservoir studies

(2) Average daily production-multiple regression

(3) Average daily production-exponential curve fit

(4) Historic decline rate

*Economic limit is considered to be 2 BOPD/well from 0-5,000 ft and 4 BOPD/well below 5,000 ft.

TABLE 17—Comparison of oil pool reserve estimates.

Pool	Remaining primary and secondary reserve as of 1-1-77 (bbls) Sipes, Williamson & Aycock, Inc.	NMBMMR[1]	% Difference S,W & A over (+) or under (-) NMBMMR	% Undeveloped secondary acreage
Artesia Queen-Grayburg-San Andres	9,526,435	2,624,444	+72	44
Caprock Queen	1,365,004	845,262	+34	15
Cato San Andres	1,244,935	336,522	+73	76
Chaveroo San Andres	3,044,032	1,173,001	+61	86
Denton Wolfcamp	5,713,886	2,683,441	+53	64
Dollarhide Devonian	1,942,019	2,444,042	- 2	57
Dollarhide Tubb-Drinkard	2,677,056	1,152,080	+57	10
Drinkard	43,582,856	4,426,127	+90	91
Empire Abo	63,396,594	69,726,982	--	--
Eumont Yates-Seven Rivers	9,708,841	4,241,748	+56	86
Eunice-Monument Grayburg-San Andres	120,765,890	45,689,863	+62	97
Eunice Seven Rivers-Queen,South	13,293,147	3,939,396	+72	56
Flying M San Andres	3,577,023	2,798,221	+22	44
Grayburg-Jackson Queen-San Andres	12,129,207	12,605,218	<- 1	24
Hobbs Grayburg-San Andres	118,809,980	18,947,396	+87	77
Jalmat Yates-Seven Rivers	37,405,737	7,066,195	+81	91
Langlie-Mattix Seven Rivers-Queen	38,121,775	18,263,153	+52	53
Loco Hills Queen-Grayburg-San Andres	4,231,501	832,405	+80	35
Lovington Paddock	1,595,201	1,211,187	+24	43
Maljamar Grayburg-San Andres	28,718,540	28,547,882	<+ 1	20
Paddock	5,152,199	2,347,659	+54	94
Paduca Delaware	3,933,119	4,545,086	-12	17
Pearl Queen	5,607,272	1,120,560	+80	13
Penrose-Skelly Grayburg	2,352,533	600,812	+74	94
Scarborough Yates-Seven Rivers	3,041,354	--	--	--
Shugart Yates-Seven Rivers-Queen-Grayburg	2,698,817	6,575,618	-59	31
Square Lake Grayburg-San Andres	4,483,019	2,697,279	+40	33
Vacuum Grayburg-San Andres	75,978,598	107,312,820	-29	73
Vacuum Abo, North	19,748,481	20,815,341	<- 1	59
Vacuum Abo Reef	16,774,950	8,831,463	+47	96
Total	660,620,001	384,401,203		

1. Does not include all undeveloped secondary reserves (reserves believed obtainable from current primary producing areas based on offset waterflood performance);includes only the current level of development of enhanced recovery programs

ences may be accounted for in part by differences in parameters used in the two studies. Differences in remaining reserves are to be expected because methods used to determine reserves vary considerably. Two major factors considered in the Sipes, Williamson, and Aycock, Inc. reserve study were the inclusion of oil estimated to be recoverable from secondary projects now in progress as well as estimates of oil to be recovered from future secondary projects not yet instituted, but whose development is inferred from geological and engineering studies of the reservoirs or from the results of earlier projects in similar reservoirs. In most pools primary ultimate recovery and secondary ultimate recovery were calculated separately to find a total ultimate recovery.

In the New Mexico Bureau of Mines and Mineral Resources reserve study, a single decline curve was determined for each pool; consequently, no specific attempt was made to separate primary ultimate recovery from secondary ultimate recovery. In this study only the current development rate of secondary recovery projects is included in the projection of remaining reserves. Where enhanced recovery programs are limited, reserve estimates generally will be lower than those in the Sipes, Williamson, and Aycock, Inc. report. This was true for all pools where 60 percent or more of the pool acreage was not involved in an enhanced recovery program. In six pools (Paduca Delaware; Shugart Yates-Seven Rivers-Queen-Grayburg; Grayburg-Jackson Queen-Grayburg-San Andres; Dollarhide Devonian; Vacuum Abo, North; and Vacuum Grayburg-San Andres), Bureau of Mines reserve estimates were higher. In three of these pools the undeveloped acreage was less than 30 percent.

Pools in which reserve estimates made by the Bureau of Mines and those made by Sipes, Williamson, and Aycock, Inc. differed by more than 50 percent are: Dollarhide Tubb-Drinkard; Pearl Queen; Shugart Yates-Seven Rivers-Queen-Grayburg; Loco Hills Queen-Grayburg-San Andres; Artesia Queen-Grayburg-San Andres; Langlie-Mattix Seven Rivers-Queen; Eunice Seven Rivers-Queen, South; Denton Wolfcamp; Cato San Andres; Hobbs Grayburg-San Andres; Chaveroo San Andres; Eumont Yates-Seven Rivers; Jalmat Yates-Seven Rivers; Drinkard; Penrose-Skelly Gray-burg; Paddock; Eunice-Monument Grayburg-San Andres.

According to API, total cumulative crude oil production in New Mexico was 3.235 billion bbls as of December 31, 1976. The total cumulative production from the 30 pools contained in the enhanced recovery study was 1.806 billion bbls, which is 56 percent of the statewide total. Production of crude oil from the 30 pools was 53.77 million bbls in 1976, or 62 percent of the statewide total of 87.44 million bbls. Fifty-six percent of the 1976 production from these 30 pools was classified as primary production and 44 percent was classified as secondary production.

Additional enhanced recovery studies will be con-

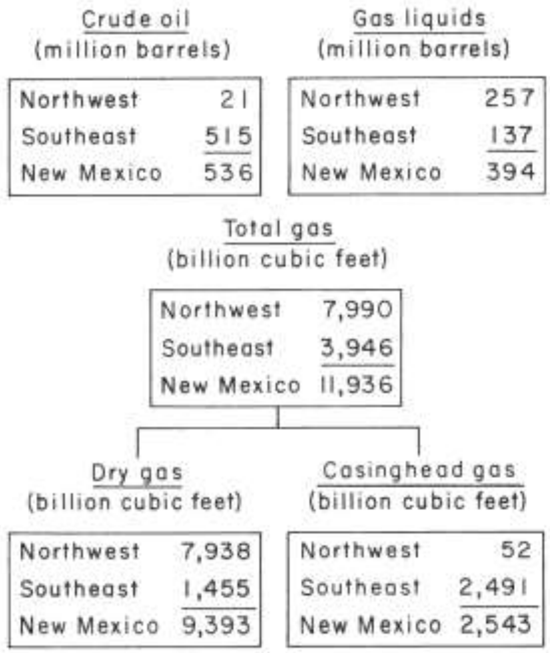

FIGURE 12—NEW MEXICO'S OIL AND GAS RESERVES AS OF DECEMBER 31, 1976 (figures reflect an adjustment in official API data. API's estimated 1976 production figures are replaced by NMOCC's 1976 production figures).

ducted during the next year in the remaining oil pools that now have currently operating projects. Reviews will also be conducted of pool studies already made where large differences in estimates are apparent. Personnel from the Office of the State Geologist and from the New Mexico Bureau of Mines and Mineral Resources will also be coordinating efforts on oil and gas resource studies. These studies will be made both in presently producing areas and in areas in which production has not previously been found.

Estimated future oil production

Since the 1969 peak of almost 124 million bbls of crude oil (exclusive of condensate) produced in New Mexico, annual production has been declining. Based on the current rate of annual decline, a computer program was developed, using a multiple regression routine, to estimate future production of oil for the state. To reflect current conditions as nearly as possible, the most recent production data were used. In making the projections, the base period used was from February 1975 through December 1976. During this period, average daily production per month declined from 252,791 bbls to 230,776 bbls. Inherent in the data for the base period are the level of exploration, development drilling of existing pools, expansion or initiation of enhanced recovery programs, abandonment of wells and pools, and the rate of decline in production. The projections are based upon the assumption that the level of development and rate of decline remain unchanged in the future. Over long periods of time conditions will change, but the projections set forth in this paper should prove reliable for periods of a year or two.

In an earlier study, projections were made using the base period April 1973 through September 1975. Predictions for the remainder of 1975 and 1976 were then compared with actual production. The error for that 15-month period was less than 0.2 percent. New projections of future production can easily be made more current as production data are obtained and incorporated into the computer program. In this way, changing conditions can be taken into consideration.

Monthly projections of crude oil production, exclusive of condensate, for 1977 and 1978 are given in table 18. Total production for 1977 is estimated to be 83.6 million bbls. If the current rate of decline is maintained, 1978 production would be 80.2 million bbls. Statewide production from 1925 through 1976 and production projections are shown on fig. 13. The rate of decline for the 1970-1973 period was 8 percent per year. From 1973-1976 the rate of decline had decreased to 3 percent per year. For the 1975-1976 base period used in making the prediction, the rate of decline averaged 3.8 percent per year overall, but from November 1975 until the end of the base period the rate of decline was 5.4 percent per year. The projected oil production (based on the 3.8 percent rate of decline) is 1.7 billion bbls to the year 2018. At that time the economic limit of 15.3 million bbls would be reached.

The economic limit is based on the number of wells producing at the end of 1976 times 3 bbls of oil per day per well. The 3-bbls limit was an average determined through an analysis of 1975 production records for each pool, the average production for each well, and the point at which pools or wells were abandoned. A continuing increase in demand and price for crude oil could lower the economic limit used for predicting future production. However, the most important factors influencing the economic limit are the distribution, capacity, and economics of the pipeline system in the state. A detailed study of this system is needed.

According to the API the proved oil reserve for New Mexico at the end of 1975 was 588 million bbls. The API reserve is based on reservoir studies that do not take into account subsequent discoveries or all potential

TABLE 18—MONTHLY PREDICTIONS FOR CRUDE OIL PRODUCTION FOR NEW MEXICO, 1977-1978 (in barrels).

	1977	1978
January	7,235,679	6,939,815
February	6,512,772	6,246,436
March	7,185,521	6,891,672
April	6,929,550	6,646,200
May	7,135,673	6,843,901
June	6,881,520	6,600,120
July	7,086,197	6,796,440
August	7,061,583	6,772,812
September	6,810,060	6,531,570
October	7,012,603	6,725,853
November	6,762,840	6,486,300
December	6,963,995	6,679,229
TOTAL	83,577,993	80,160,348

development of existing pools. The largest reserve figure for New Mexico published by API was 1.1 billion bbls at the end of 1961. Production from 1962-1975 totaled 1.5 billion bbls. During the period 1962-1975 an additional 1.0 billion bbls were found by exploration, development, or revision of previous reserve estimates. The projected production of 1.7 billion bbls, based on the 3.8 percent rate of decline, indicates that an additional 1.1 billion bbls (beyond the proved API reserve) need to be found in the 42-year period between 1977 and 2018. If, however, the 5.4 percent per year decline (as occurred in the latter part of 1975 and into 1976) continues, it would result in the future production of 1.4 billion bbls of oil and an economic life to the year 2008.

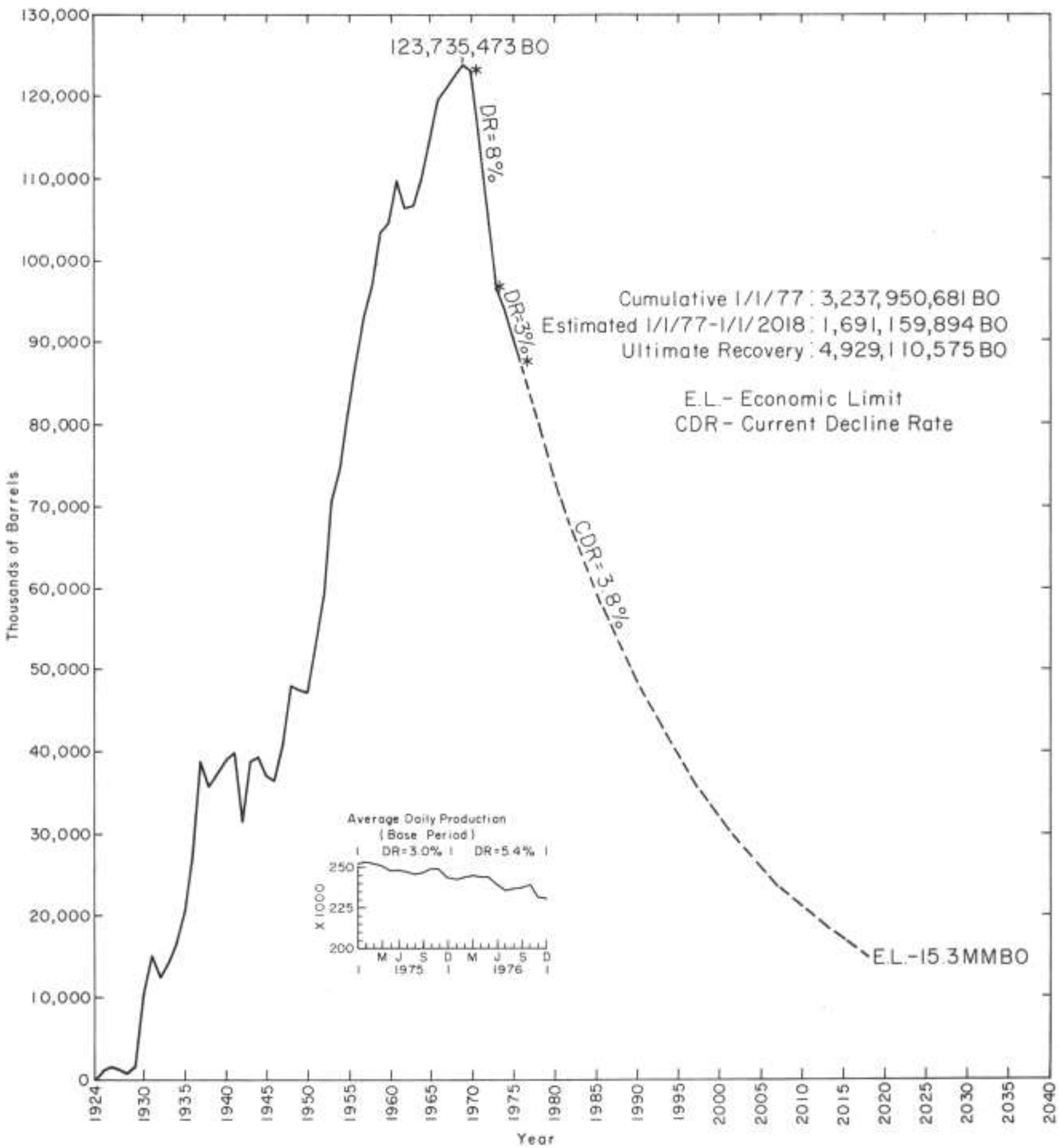

FIGURE 13—New Mexico crude oil production with production projection.

Coal

by 0. J. Anderson
Office of the State Geologist

Production

In 1976 New Mexico coal production totaled 9,980,322 tons, according to statistics supplied by the State Bureau of Revenue. This represents a five-percent increase over 1975 production figures and places the state 14th nationally in coal production. The coal is valued at 67.5 million dollars versus approximately 61 million dollars for 1975. The average price for all New Mexico coal was $7.21 per ton according to Bureau of Revenue statistics, but this average is somewhat misleading because the actual prices received by producers range from less than $5.00 to more than $25.00 per ton.

Over 90 percent of New Mexico production is steam coal; steam coal demand in the U.S. is increasing and will continue to increase as commercial boilers and utility companies gradually convert to coal. Conversion, however, is not taking place as quickly as many government officials would like. The main problems with conversion are the capital costs and the problems in meeting local air quality regulations and/or securing a supply of compliance (low sulfur) coal. The capital cost problem may be alleviated somewhat by current research, which is directed at developing a pulverized coal-fuel oil slurry that will burn in a conventional oil-fired boiler with minor modification.

For the months of February, March, and April in 1977, U.S. electrical energy was supplied by the following fuels at the indicated percentages *(Coal Week,* July 4, 1977):

Boiler Fuel	*Percent of Total U.S. Electrical Energy Generated (Feb.-Apr., 1977)*
Coal	47
Oil	17
Natural gas	13
Nuclear	12
Hydroelectric	11

At present New Mexico exports only a small percentage of its steam coal, but that situation will change considerably over the next decade as exports to neighboring states increase very significantly. In 1976 the Amcoal mine (formerly Sundance) southeast of Gallup resumed production, and approximately 72,000 tons were mined and shipped to Arizona. The McKinley mine, operated by the Pittsburg and Midway Coal Mining Company, increased production from less than 500,000 tons in 1975 to 842,338 tons in 1976; the coal was sold for use in Arizona. In San Juan County the Navajo mine, operated by Utah International, Inc., produced 6,756,236 tons compared to 6,073,000 the previous year, and the San Juan mine produced 1,223,670 tons for a total San Juan County production of 7,979,906 tons. Kaiser Steel Corporation produced 845,000 tons of metallurgical grade (coking) coal in Colfax County. Essentially all of this coal was produced by underground methods, but the York strip mine is in production and is being further developed. Except for occasional spot sales, Kaiser ships all of its production to its coking ovens in Fontana, California.

Coal outlook

The National Environmental Policy Act of 1969 (NEPA) requires an EIS (Environmental Impact Statement) for any Federal action that may significantly affect the quality of the human environment. In 1970 the Department of the Interior ruled that an EIS was necessary before proceeding with further leasing of Federal coal lands; a moratorium was imposed on leasing as well as on the issuance of prospecting permits. In 1973 the Department of the Interior adopted a policy that distinguished between long-term and short-term actions. The short-term action provided, among other things, that the complete moratorium on prospecting permits would remain in effect, but that new Federal leases could be issued to maintain existing mines or to supply reserves for production in the immediate future. During 1973 the Bureau of Land Management also established some long-term criteria in the form of a new coal-leasing system entitled Energy Minerals Allocation Recommendation System (EMARS). This system in itself was a Federal action requiring an EIS. Therefore, in May 1974 a draft EIS was filed by the Department of the Interior with the Council on Environmental Quality.

Ample time was allowed for public commentary and review by other Federal agencies; in September 1975 the final EIS evaluating the new coal leasing program was released. Another four months lapsed before the Secretary of the Interior announced the implementation of the new coal-leasing policy based upon the revised EMARS (Energy Minerals *Activity* Recommendation System) and expressly lifting the moratorium on leasing. The new competitive leasing system was to become fully operational as soon as possible.

In February 1976, however, other Federal agencies began casting doubt on the need for a new coal-leasing policy. Environmental groups set upon the final EIS and declared it inadequate in terms of NEPA requirements.

Minor revisions were made in May 1976; in June the Department of the Interior issued a call for nominations of coal land for leasing. Industry responded by nominating 680 tracts in eight states. The BLM was apparently secure in the knowledge that they had a viable new leasing program including a way to process all the pending preference right lease applications (PRLA's). In the San Juan Basin of New Mexico a call for specific coal-mining proposals went out from the district BLM office, requesting company replies by December 1, 1976, so that work on a regional coal EIS could begin. Eleven companies responded, and the Bisti-Star Lake EIS boundaries were drawn (fig. 14); a team of specialists

FIGURE 14—AREA COVERED IN BISTI-STAR LAKE ENVIRONMENTAL IMPACT STATEMENT (source: BLM, Albuquerque office).

TABLE 19—COAL-LEASING STATISTICS FOR BISTI-STAR LAKE ENVIRONMENTAL IMPACT STATEMENT AREA (source: BLM).

	Coal acreage	% of total coal acreage in EIS area	% of total EIS area
ACTIVE AND PROPOSAL COAL ACREAGE[1]			
Leases under development (being mined)	15,724	3.4	0.3
Acreage on which mining proposals were submitted	160,230	35.1	3.3
Subtotal	175,954	38.5	3.6
COAL ACREAGE NOT INCLUDED IN SPECIFIC MINING PROPOSALS			
Nominations	185,494	40.6	3.9
Federal land under lease	17,673	3.9	0.4
Preference right lease applications (PRLA)	77,590	17.0	1.6
Subtotal	280,757	61.5	5.9
TOTAL	456,711	100.0	9.5

1. Division of active and proposal coal acreage ownership

	Acreage Federal	State	Fee	Total
Leased	29,850	16,249	22,456	68,555
PRLA	69,991			69,991
Nominated	33,768			33,768
Other	3,480	160		3,640
Total	137,089	16,409	22,456	175,954

was assembled, and work began. Completion was set for May 1978.

However, a suit was filed in United States District Court by the Natural Resources Defense Council and others against the Department of the Interior. The plaintiff claimed that the EIS for the new coal-leasing program failed to comply with NEPA. The Court recently decided in favor of the plaintiff; on September 27, 1977, U.S. District Judge John H. Pratt ruled that the final EIS 1) contravenes the purpose of NEPA as an environmental full-disclosure law, 2) is inadequate with regard to the section concerning EMARS, and 3) failed to consider alternatives to the present policy.

This ruling severely limits the scope of the Bisti-Star Lake EIS. Land nominated under the now invalidated EMARS system cannot be considered for leasing. In addition the PRLA's can only be considered in a general way. Therefore, a decision cannot be reached based on this statement to lease or not to lease. Statistics on coal acreage in these various categories are given in table 19.

San Juan Basin

EXPLORATION AND DEVELOPMENT AFFECTED BY THE BISTI-STAR LAKE EIS—Notwithstanding the limitations imposed by the district court's ruling, the 11 company proposals received by the BLM on or before December 1, 1976, are presented here. Perhaps only two of these can now be acted upon within the framework of the coal EIS now in progress. The remainder contained nominated and/or PRLA land; decisions on these will have to await further action and environmental analysis so the production schedules given may not be realized.

In 1976, Amcoal, Inc., a subsidiary of Amcord, Inc., a cement-manufacturing company in Phoenix, Arizona, took over the Sundance Coal mine just southeast of Gallup in T. 14 N., R. 17 W. By the end of 1976 the mine was producing at an annual rate of about 160,000 tons per year for local markets as well as for the cement-manufacturing operation in Phoenix. Reserves at this mine will be depleted in 1979, but the company has nominated a nearby Federal coal section for leasing (section 8, T. 14 N., R. 17 W.). The section contains approximately 3.3 million tons of strippable or recoverable reserves, and mining is proposed to extend over an 11-year period beginning in 1980. The first seven years of the mining period would involve only strip-mining operations, but the last four may include underground mining as well.

Arch Mineral Corporation PRLA's and nominations total more than 20,000 ac. On this property the corporation has proposed to mine a total of 142 million tons of coal from two mining units during the 1981-2010 period. The property is located for the most part in T. 23 N., R. 12 W. and T. 22 N., R. 10 W. Mining Unit I will begin in 1981 at 3 million tons per year through 2001. Mining Unit II will begin operation in 1984 at 3 million tons per year through 2009, with an additional 1 million tons being taken in 2010; this mining activity will supposedly deplete both units.

Carbon Coal Company is a subsidiary of Hamilton Brothers Petroleum Company, with primary operations in Colorado. On its lease holdings in T. 16 N., R. 19 W. and on one section of Federal coal land nominated in T. 15 N., R. 19 W., Carbon Coal proposes to mine a total of 18.06 million tons of coal during an 11-year period beginning in late 1978 or early in 1979 and ending in 1989. The coal will be extracted by stripping operations at a rate of 1.6 million tons per year and sold to Arizona Public Service Company at Benson, Arizona.

Chaco Energy Company, a subsidiary of Texas Utilities, has proposed to mine both fee and Federal coal in the Gallo Wash area and in the Star Lake area. In both areas the fee land is almost entirely owned by Santa Fe Industries and contains shallow coal deposits. In the Gallo Wash area Chaco Energy proposes to mine approximately 120 million tons of coal between 1985 and 2003. In the Star Lake area a total of 244.9 million tons of coal would be mined during the period beginning in 1980 and continuing through 2014.

Year		Estimated production
Gallo Wash	*Star Lake*	*(tons/year)*
1985	1980	2,000,000
1986-87	1981-82	3,200,000
1988-91	1983	5,100,000
1992-94	1984-86	6,000,000
	1987-89	7,000,000
1995-2002	1990-2013	8,000,000
	2014	400,000
2003		4,300,000

Consolidation Coal Company, a subsidiary of Continental Oil Company, has proposed an underground coal-mining operation, largely on Federal land, in the La Ventana area (T. 19 and 20 N., R. 1 W.). They propose to begin mining Menefee Formation coal in 1987 at the rate of nearly 3 million tons per year for 20 years, extracting a total of 61.5 million tons, largely for out-of-state markets.

A proposal to mine 82 million tons of coal over a 41-year period has been submitted by Eastern Associated Coal Corporation. The coal would be mined almost entirely on Federal land in T. 23 N., R. 11 and 12 W. and in T. 24 N., R. 12 W. Beginning in 1982 the production would be a uniform 2 million tons a year.

Beginning in 1982, Freeman-United Coal Mining Company proposes to mine 59 million tons of Fruitland Formation coal in T. 19 N., R. 5 W. over a 20-year period. Production will average approximately 3 million tons per year.

Peabody Coal Company proposes to mine approximately 48 million tons of coal from two separate areas during the 1981-2012 period. The Star Lake East mine, to be located in T. 19 N., R. 6 W., would go into production in 1983 and continue through 2004. The Gallo Wash mine located in T. 21 N., R. 8 W. (in Fruitland Formation coal) would consist of three stripping pits comprising one mine. Production would begin in 1986 and continue through the year 2012 according to the schedule given below:

Year		Estimated production
Star Lake East	*Gallo Wash*	*(tons/year)*
1983-84	1986	200,000
1985-2003	1987-2001	500,000
2004		370,000
	2002-2010	3,000,000
	2011	1,900,000
	2012	254,000

The coal would be processed (washed) and loaded at Chaco Energy facilities.

A Gulf Oil subsidiary, the Pittsburg and Midway Coal Company, has been operating the McKinley mine northwest of Gallup since 1961. Production throughout this time has been between 400,000 and 500,000 tons per year, but Pittsburg and Midway now proposes to increase this tonnage significantly by expansion of strip-mining operations on reservation land. In 1978 production will go to 2.5 million tons; beginning in 1980, annual production will go to 5 million tons. Most of the additional coal will continue to go to Cholla, Arizona. The mine will be depleted by the year 2000.

The Salt River Project, an Arizona utility consortium, has been leasing (from the State) or nominating (on Federal land) the deeper lying Fruitland Formation coal deposits, especially in T. 23 and 24 N., R. 10 W., due west of Nageezi. The project proposes underground mining operations in this area, with production beginning in 1986 at a rate of 2.9 million tons per year. Ultimately a total of nearly 207 million tons will have been extracted at this site, largely from Federal and State lands. A tentative production schedule is given below:

Year	*Estimated production (tons/year)*
1986-89	2,900,000
1990-2021	5,400,000
2022-2030	2,500,000

A Public Service Company of New Mexico subsidiary, Western Coal Company, has announced a generating plant construction program to be carried out jointly with Plains Electric Generation and Transmission Cooperative and El Paso Electric Company. A total of four 500-megawatt electrical coal-fired units are tentatively planned for the Bisti area in T. 23 N., R. 13 W. and are projected to be on-line in 1983, 1989, 1990, and 1991. To supply coal for the generating complex, Western Coal Company has proposed to begin mining Fruitland Formation coal in T. 23 and 24 N., R. 13 W. sometime in 1981. A production schedule has been given:

Year	*Estimated production (tons/year)*
1981	300,000
1982-1987	3,000,000
1988-89	6,000,000
1990-91	9,000,000
1992-2012	12,000,000
2013	1,500,000
	Depleted

A total of 301.8 million tons is involved in this production schedule, and the mining eventually will spread over perhaps 15,725 ac. The generating plant itself will cover 2,500 ac, but the exact site has not been chosen. The matter of setting aside and preserving a portion of the Bisti Badlands has not been resolved as yet.

In addition, Western Coal Company plans to develop an underground operation near its San Juan open pit. This expansion would ultimately add as much as 2 million tons per year to the San Juan generating plant coal supply. A proposed production schedule is as follows:

Year	*Estimated production (tons/year)*
1980	300,000
1981	750,000
1982	1,550,000
1983-2020	2,000,000
2021	1,400,000
	Depleted

When the Bisti-Star Lake EIS is released (probably early 1979), a copy will be filed with the Council on Environmental Quality, and a 30-day waiting period must be observed before any company or individual may cite the statement. However, as noted, a decision on whether or not to lease nominated and/or PRLA land contained in proposal areas cannot now be rendered on the basis of the EIS in progress. All but two mining proposals contained such land. Most companies who submitted proposals must now await the revision and approval of the Federal coal-leasing program and completion of another environmental analysis dealing with coal development in the Bisti-Star Lake area.

COAL DEVELOPMENT PROJECTS NOT AFFECTED BY THE EIS—In addition to the 11 company proposals discussed briefly above, there are several other proposed New Mexico coal development projects, but they do not involve Federal (public domain) coal lands. They are 1) the Tucson Gas and Electric Company proposal to mine coal on the Santa Fe Railroad Company property; 2) the very recent announcement by Consolidation Coal Company and El Paso Natural Gas Company to jointly supply Navajo Indian Reservation coal to the Arizona Salt River Project; 3) the Navajo Tribal Council proposal to mine reservation coal near Standing Rock; and **4)** the coal-gasification plant proposals by WESCO (Western Gasification Company) and El Paso Natural Gas Company.

The Tucson Gas and Electric Company announced early in 1977 plans to construct three 350-megawatt coal-fired generating units near Springerville, Arizona, to become operational in 1985, 1988, and 1991. They have leased coal property from the Santa Fe Pacific Railroad Company subsidiary, Gallo Wash Coal Company, and plan to begin strip mining operations in 1984. Production will increase from an initial 1.8 million tons per year to 4 million tons per year by 1991, an amount sufficient to fuel all three units.

The Consolidation Coal Company/El Paso Natural Gas Company project will begin producing coal from the Con Paso mine near Burnham in July 1978. The first year, it will produce 300,000 tons; by the fifth year, it will be producing 6.4 million tons. The coal will be bought and used as boiler fuel by the Arizona Salt River Project. Life of the mine is projected to be at least 38 years.

The Navajo Tribal Council has at this time announced only an interest in a plan to construct a coal-fired electrical generating plant northwest of Crownpoint. Coal for the plant would be mined from the Menefee Formation in the Standing Rock-Cleary coal area on the reservation.

The WESCO coal-gasification project has faced delay after delay; however, many of the environmental considerations involved have been solved. The final environmental statement was filed in January 1976, and the company has a Department of the Interior contract for San Juan River water. What WESCO apparently is waiting for at the present time is 1) congressional action providing for some form of a Federal loan guarantee to assist in financing the project; 2) approval of the business site lease agreement by the Navajo Tribal Council; and 3) to see whether or not their product will be held to the same price controls as naturally produced gas, which is the present case. Company officials estimate the cost of the gas to be $3.60 per thousand cu ft (1977 dollars).

While even less is known of the proposed El Paso Natural Gas Company gasification project, it appears to be delayed indefinitely.

In table 20 and fig. 15 the coal development proposals discussed herein are illustrated with the exception of the Navajo Crownpoint proposal and coal gasification pro-

TABLE 20—PROPOSED NEW MEXICO COAL PRODUCTION BY COMPANY THROUGH THE YEAR 2000 (exclusive of 1976 base of 9,980,323 short tons).

	1977	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
Amcoal	.16	.16	.16	.30	.30	.30	.30	.30	.30	.30	.30	.30	.30	.30										
Arch MU-I					3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
MU-II								3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Carbon Coal			1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6											
Chaco Enery																								
Star Lake				2.0	3.2	3.2	5.1	6.0	6.0	6.0	7.0	7.0	7.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Gallo Wash									2.0	3.2	3.2	5.1	5.1	5.1	5.1	6.0	6.0	6.0	8.0	8.0	8.0	8.0	8.0	8.0
Consolidation Coal											3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Eastern Assoc.						2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Freeman-United						2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Peabody																								
Star Lake East							.2	.2	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
Gallo Wash										2	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
Pittsburg-Midway	1.2	2.5	4.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Salt River Project										2.9	2.9	2.9	2.9	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Western Coal-																								
Bisti					.3	3.0	3.0	3.0	3.0	3.0	3.0	6.0	6.0	9.0	9.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
San Juan Underground				.3	.75	1.55	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Consolidation Coal/El Paso Natural Gas		.30	.75	1.0	4.3	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Tucson Gas & Electric									1.8	1.8	1.8	3.5	3.5	3.5	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Annual Total	1.4	3.0	6.5	10.2	18.5	28.1	31.6	35.5	39.6	43.9	48.2	54.8	54.8	59.7	59.9	63.8	63.8	63.6	65.8	65.8	65.8	65.8	65.8	65.8

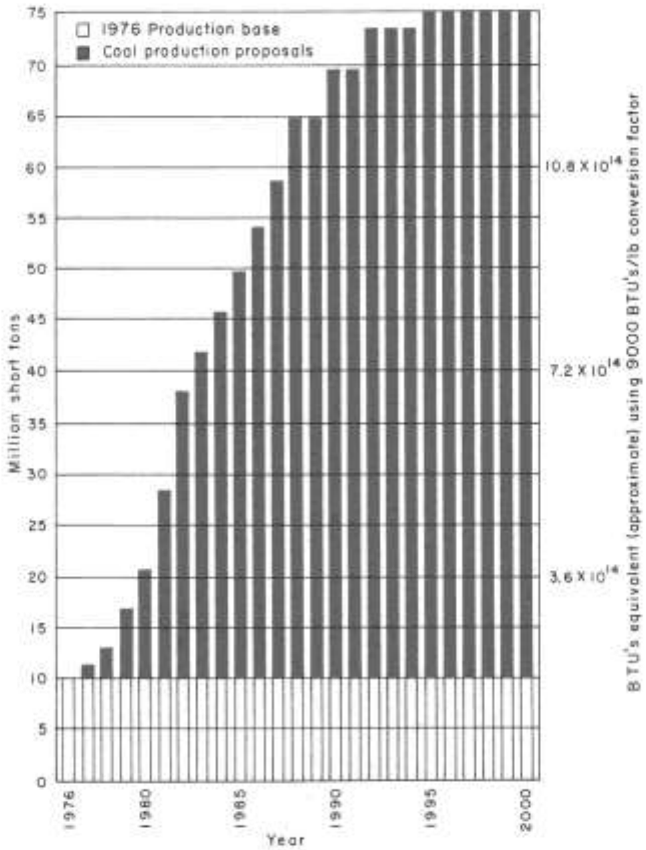

FIGURE 15—PROJECTED COAL PRODUCTION IN NEW MEXICO TO YEAR 2000.

posals. These two are much too uncertain for inclusion. Fig. 15 shows that New Mexico is very likely to have a 70-million-tons-per-year coal industry by 1992 provided that the 1976 base of 9.9 million tons remains stable or expands through this time frame.

Other areas

Considerable interest in coal areas outside the San Juan Basin has been demonstrated by the number of nominations received by the State Land Office and the BLM office on State and Federal lands respectively. A parallel interest may be assumed to exist on the adjacent and nearby fee land; however, leasing activity in the private sector is difficult to follow.

In eastern Colfax County approximately 22 sections of Federal land have been nominated for coal leasing. The land is in T. 31 and 32 N., R. 24 and 25 E. Any commercial quantities of coal found here would be in the Yankee coal bed of the Raton Formation. Here on the eastern edge of the Raton coal field, most coal seams are less than 4 ft thick, are limited in area, contain partings of shale or bone coal, and are generally less desirable for manufacture of coke than are the coals in the western portion of the field.

In the western Raton coal field in Colfax County, Kaiser Steel Corporation owns 530,000 ac (equivalent of 828 sections) of prime coal lands. In York Canyon, Kaiser Corporation mines coking coal from the Vermejo Formation, which underlies the Raton Formation and which generally has thicker, more extensive coal beds. Kaiser's property borders on the Vermejo Park Ranch, owned by Pennzoil Corporation, and is entirely within the original Maxwell Land Grant.

In the Datil Mountain coal area of Socorro County, Federal land has been nominated in T. 1 N., R. 5 and 6 E. Seam thickness here is generally 3-4 ft, and ranges up to 7 ft, but reserves of Mesaverde Formation coal are quite limited. Further east in the county, in T. 4 S., R. 3 and 4 E., both Federal and State land have been nominated.

Federal land in the northern portion of the Datil Mountain coal area in Valencia County has received nominations. In T. 7 and 8 N., R. 9 W., eight sections have been nominated for coal leasing. Seam thickness here ranges from 3-7 ft, but some of the area is overlain by volcanic rocks, making stripping operations nearly impossible. A few miles to the south in T. 5 N., R. 9 W., several State tracts have been nominated in an area where volcanics are less of a problem.

Eleven sections of Federal land underlain by thin seams of Mesaverde coal have been nominated along the western edge of Bernalillo County. In addition three State-owned tracts have received nominations. For the most part the land is in T. 9 and 10 N., R. 1 and 2 W.

Numerous State-owned tracts have been nominated in the Carrizozo area somewhat west of the Capitan coal field in Lincoln County. In this vicinity there is no federally owned land; further eastward the Lincoln National Forest begins, but no leasing activity has been noted.

Reserves

A recent study funded by the U.S. Bureau of Mines and the New Mexico Energy Resources Board on deep Menefee Formation coal resources in the 250 to 4,000 ft depth interval indicates the presence of approximately 12 billion tons in seams 2 ft thick or greater. This estimate represents a considerable decrease compared to an earlier estimate of 115 billion tons. The earlier estimate, however, included coal resources lying at depths greater than 4,000 ft as well as resources that are now excluded as a result of reinterpretation of geophysical logs. Neither of these estimates includes other Mesaverde deep resources which may be present in the Gallup area. This area is characterized by complex inter-tonguing of marine and nonmarine units that have not been drilled sufficiently to estimate coal reserves with accuracy.

The Office of the State Geologist has contracted out a study of San Juan Basin strippable coal reserves. Work completed to date on this project has permitted revisions of Fruitland Formation reserves to a depth of 150 ft. Table 21 shows San Juan Basin strippable reserve statistics as they stood previous to the study. Fruitland Formation reserves to a depth of 150 ft are listed as 2,440.7 million tons. The recent study indicates that this figure should be revised upward to about 3,090, which is a 650-million-ton increase. This in turn will raise the total San Juan Basin reserves (to a depth of 250 ft) from 5,711.6 to 6,361.6 million tons. Revisions of strippable reserves in the Mesaverde Group are not complete at this time, although preliminary work indicates that there will be considerable increases in at least three of the fields.

TABLE 21—ORIGINAL STRIPPABLE COAL RESERVES IN NEW MEXICO IN MILLIONS OF SHORT TONS (source: Shomaker, Beaumont, and Kottlowski, 1971).

Coal field or area	Overburden less than 150 ft Measured (column 1)	Combined[1]	Inferred (column 2)	Overburden 150 ft to 250 ft Measured (column 3)	Combined[1]	Inferred (column 4)	Total
Mesaverde Group							
Gallup		270.0			88.0		358.0
Newcomb			78.5			6.3	84.8
Chaco Canyon			31.0				31.0
Chacra Mesa							
San Mateo			21.2				21.2
Standing Rock			63.5			75.0[2]	138.5
Zuni			6.2				6.2
Crownpoint			15.0				15.0
South Mount Taylor			1.4				1.4
East Mount Taylor							
Rio Puerco							
La Ventana			15.0				15.0
Mesaverde total[3]		501.8			169.3		
Fruitland Formation							
Fruitland	93.0			65.0			158.0
Navajo		1,024.7			1,352.8		2,377.5
Bisti			958.0			912.0	1,870.0
Star Lake			365.0			270.0	635.0
Fruitland total[3,4]		2,440.7			2,599.8		
Total[3]		2,942.5			2,769.1		5,711.6

1. Some portions limited by stripping ratio; figures for measured and inferred reserves not released by companies
2. Estimates for Standing Rock in column 4 are being revised
3. Includes measured, inferred and combined
4. Fruitland total to 150 ft has been revised to 3,090; see text

The study that permitted revisions in Fruitland coal reserves also revealed information on coal ownership. Four land ownership categories and the reserves to 150 ft in each one are shown in table 22. The Indian category includes both reservation and Indian-allotted land.

It is believed these estimates account for virtually all of the strippable Fruitland coal beneath less than 150 ft of overburden. Additional drilling may result in upward revisions of the deeper reserves.

TABLE 22—FRUITLAND FORMATION COAL OWNERSHIP AND RESERVE STATISTICS TO A DEPTH OF 150 FT AS OF SEPTEMBER 1977 (source: Office of the State Geologist).

Ownership category	Coal Reserves (millions of tons)	% of reserves in each ownership category
Indian	1,950	63.0
Federal	800	25.9
Fee	270	8.8
State	70	2.3
Total	3,090	100.0

Uranium

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Production

In 1976, 3,401,000 tons of uranium ore were mined and processed in New Mexico to yield 6,500 tons of U308 (ERDA, 1977a). This amounted to 46 percent of the nation's U_30_8 production (table 23), which is a slight increase over the 1975 percentage. All of the increase in the national U_30_8 production, which went from 12,300 tons in 1975 to 14,000 tons in 1976, was due to increases in production in New Mexico and Wyoming. New Mexico production increased from 5,500 to 6,500 tons; Wyoming production increased from 3,700 tons to 4,400 tons, or 31 percent of the nation's total production. Fig. 16 shows uranium production by state for the period 1963 through 1976.

The gross value of 1976 U_30_8 production in New Mexico was listed as $163,628,000 by the New Mexico Bureau of Revenue. This gives a weighted average price of about $12.50 per lb, up considerably over the previous year's price of $8.00 per lb. Taxes due by the industry in 1976 totaled $1,442,204, which includes both a resource excise tax and a severance tax. During the 1976 legislative session a new severance tax bill was passed, which will significantly increase the revenue collected by the state from the uranium industry.

Employment in the New Mexico uranium mining and milling industry was up 32 percent over 1975. During 1976, 4,879 persons were involved in uranium production, compared with 3,709 the previous year. New Mexico now employs approximately 50 percent of the U.S. uranium production work force.

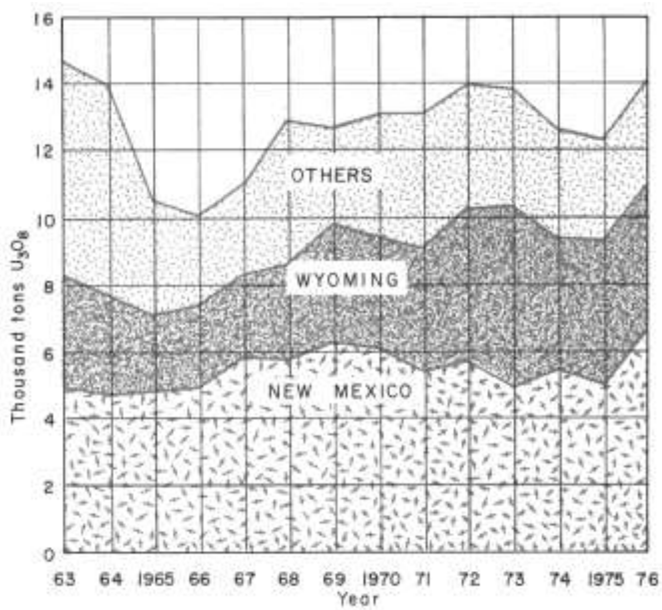


FIGURE 16—CUMULATIVE PRODUCTION OF U_3O_8 BY STATE, 1963-1976 (source: ERDA, 1977a).

Exploration and development

Drilling

Total footage drilled in 1976 in the United States reached an all-time high of 34 million ft; this figure constitutes a 31-percent increase over the 1975 footage of 26 million ft (ERDA, 1977a). Of the 34 million ft, approximately 20 percent was drilled in areas more than 50 mi from existing production centers, compared with 25 percent in 1975. Total exploration drilling accounted for 19 million ft, which was 57 percent of the total; development drilling, which defines the size, shape, and grade of an ore deposit, accounted for the remaining 43 percent, up from 35 percent in 1975 (ERDA, 1977a).

Drilling on a state-by-state basis is shown in table 24. Despite a decrease in footage drilled (from 12,054,000 in 1975 to 11,720,000 in 1976), Wyoming remained number one in drilling activity. New Mexico drilling footage doubled over the same period, from 5,690,000 to 11,020,000.

ERDA (1977a) has estimated that 301 drill rigs were available to the uranium industry nationwide in 1976, compared to 245 the previous year. They also estimated that the number of commercial well-logging service companies that can serve the uranium exploration effort increased from 100 in 1975 to 122 in 1976.

TABLE 23—DISTRIBUTION OF 1976 U_3O_8 PRODUCTION BY STATE (source: ERDA, 1977a).

State	Ore weighed and sampled by mills		
	Tons ore	Tons U_3O_8	% total U_3O_8
New Mexico	3,401,000	6,500	46
Wyoming	3,315,000	4,400	31
Others (Colo., Tex., Utah, Wash.)	2,482,000	3,100	23
Total	9,198,000	14,000	100

The following 25 companies are involved in exploration and development work in northwestern New Mexico:

- Anaconda Co.
- Atlantic Richfield Co.
- Bokum Resources
- Continental Oil Co.
- Energy Fuels Co.
- Exxon Co., U.S.A.
- Frontier Mining Corp.
- Getty Oil Co.
- Gulf Mineral Resources Co.
- Houston Oil & Minerals
- Keradamex, Inc.
- Kerr-McGee Corp.
- Lucky Mc Uranium Corp.
- Mobil Oil Co.
- Musto-Canorex
- Phillips Petroleum Co.
- Pioneer Nuclear, Inc.
- Ranchers Exploration & Development Corp.
- Reserve Oil & Minerals Corp.
- Sohio Petroleum Co.
- Teton Exploration Drilling Co., Inc.
- Todilto Exploration & Development Corp.
- Union Carbide Corp.
- United Nuclear Corp.
- Western Nuclear, Inc.

Throughout the past year these companies have been

TABLE 24—Distribution of 1976 uranium drilling by state (source: ERDA, 1977a).

State	Drilling (ft)	% Total
Wyoming	11,720,000	34.5
New Mexico	11,020,000	32.4
Texas	2,990,000	8.8
Utah	1,970,000	5.8
Colorado	2,990,000	8.8
Others[1]	3,310,000	9.7
Total	34,000,000	100.0

1. Includes Alaska, Arizona, California, Idaho, Montana, Nevada, North Dakota, Oklahoma, Oregon, South Dakota, Washington, and eastern United States

keeping active 30-40 exploration drilling rigs plus another 30-35 development rigs. These figures, however, do not include any exploration work that may have recently begun on the Navajo Indian Reservation.

Essentially all the activity has been within the area known as the Grants mineral belt, with the exception of activity by Atlantic Richfield Company, which has been drilling in the Chama Embayment east of Canjilon; Union Carbide Corporation, which has been working in the Hagan Basin, northeast of Albuquerque; and Gulf Mineral Resources Company, which is drilling in Catron County. The Grants mineral belt is widening somewhat as mining companies show a willingness to move downdip and go to greater depths to extract ore from the Morrison Formation. Phillips Petroleum Company will be mining from depths of 3,400 ft in T. 19 N., R. 11 W., and Exxon Company has been conducting exploration drilling in T. 18 N., R. 7 W., just south of Star Lake, where the Morrison Formation may lie at depths up to 4,000 ft.

Mainly because of price increases, mining companies have relaxed the criteria used in determining whether or not a prospect will develop into a mine. They are now looking seriously at 6-ft thicknesses of 0.08 percent ore at depths greater than 2,500 ft, whereas several years ago the criteria was about 6 ft of 0.15 percent ore at depths of 2,000 ft or less.

Mine and mill development

At the present time the Office of the State Geologist is aware of plans by the below-listed 10 companies to develop or expand uranium mines or uranium ore processing mills in New Mexico. Possibly before the year is out other announcements will be made by uranium-mining companies.

A modification and expansion project is underway at the Anaconda Company Bluewater uranium mill. Mill capacity will be increased from the present 2,500 tons of ore per day to 4,600 tons per day by January 1978 and to 6,000 tons by January 1979.

Bokum Resources is in the process of sinking a shaft in T. 13 N., R. 5 W., just west of the village of Marquez. As of mid-1977 they were down in excess of 650 ft; the total depth of the shaft will be approximately 2,100 ft. A June 1978 production date has been given.

Continental Oil Company will probably develop mines at three different locations; they will be located 1) in the Bernabe Montano Grant in T. 11 N., R. 2 W., 2) near Borrego Pass in T. 16 N., R. 11 W., and 3) near Crownpoint in T. 17 N., R. 13 W. All of these supposedly have 1982 production dates. Continental also plans to construct and operate its own mill, probably at the Crownpoint site.

Gulf Mineral Resources Company is proceeding with shaft-sinking work at two locations: the San Mateo mine shaft in T. 13 N., R. 9 W., which has been contracted out to the Harrison Western Corporation, and the Mariano Lake shaft in T. 15 N., R. 14 W., which has been contracted out to Stearns and Rogers Construction Company. Gulf plans to be in production at San Mateo no later than 1980 and will begin operating its own uranium mill also at that time.

Kerr-McGee Corporation is sinking a shaft in section 18, T. 12 N., R. 3 W. The ore deposit to be mined is in the 700-1,000 ft depth range and they project production some time in 1978. Kerr-McGee plans to open a new mine each year during the next several years.

Mobil Oil Company announced in July 1977 plans to conduct in situ leaching tests for uranium recovery on a pilot-plant scale beginning in 1978. The tests will be carried out on lease holdings in the Crownpoint area on which Mobil has located two prospects, the Crownpoint South and the Monument, just east of Crownpoint. Mobil's 10-year lease on the Indian-allotted land specifies that Mobil must be in production by 1982. With this time limit in mind Mobil has also been making plans to develop the prospect into a conventional mine; however, preliminary in situ tests have produced encouraging results.

Core leachability tests have been in progress for some time, and the methodology Mobil will use has already been developed at its Texas in situ project. Drilling of test wells to determine hydrologic factors and quality of the formation waters will begin later this year. Design and construction of the pilot test unit will be completed by April 1978, and the pilot test will go into operation in mid-1978 and continue for 2 1/2 or 3 years.

Phillips Petroleum Company has selected a contractor for the construction of a shaft near Seven Lakes in T. 19 N., R. 12 W. to a total depth of 3,400 ft. Eventually four shafts will be sunk, two for ventilation and two for production. According to plans, actual construction work will begin by late 1977. Production is scheduled for 1980 with an ore processing mill possibly also ready by that time.

Union Carbide Corporation has been drilling three dewatering holes at the site of a proposed mine shaft or decline on State land in T. 13 N., R. 6 E. Actual work on the 19-degree decline began in May 1977. The decline will be 275 ft long, terminating in ore 120 ft below the ground surface. A pond 50 ft by 100 ft is being constructed to contain the water produced from the three wells and allow it to percolate back into the ground. Possibly, this project will become a solution mining operation. If it does go into production it will mean the third State lease to produce uranium, the other two being in the Ambrosia Lake mining district.

United Nuclear Corporation is sinking a shaft near its St. Anthony open-pit mine in T. 11 N., R. 4 W. The shaft site was moved from its original location and as a result will be approximately 500 ft deep, somewhat deeper than originally planned. A basalt flow over the Jackpile sand makes stripping operations unfeasible here.

Currently United Nuclear is transporting ore from its St. Anthony pit to Sohio's mill at the nearby Jay-Jay mine for processing. United Nuclear has, however, just completed a uranium-ore processing mill at its Church Rock mine in T. 17 N., R. 16 W., but the distance would prohibit hauling ore from the St. Anthony pit to Church Rock; capacity of the new mill is 2,000 tons of ore per day. United Nuclear-Homestake Partners has nearly completed a 625-ft decline in section 15, T. 14 N., R. 10 W. This work has been under contract to American Services Corporation. Production began in late 1977.

As a result of all this activity, New Mexico production of U_3O_8 will go from approximately 13 million lbs (6,500 tons) in 1976 to approximately 17 million lbs (8,700 tons) in 1978, based on responses the New Mexico Bureau of Revenue received from producing companies.

New Mexico uranium-mill production capacities in 1976, projected through 1980, are listed in table 25. Calculations show that if 17,000,000 pounds of U_3O_8 are to be produced in 1978, mills will have to be operated at 85 percent capacity with 0.15 percent ore and at only 63 percent capacity with 0.20 percent ore.

Reserves and potential resources

Ore reserve estimates are derived from drill-hole and other engineering data made available to ERDA, Grand Junction Office, by the uranium mining and exploration companies. Reserves are evaluated with respect to forward-cost categories, which are intended to reflect production costs yet to be incurred in producing a pound of U_3O_8 in a particular category. The categories in use by ERDA at present are $10, $15, and $30 per lb U_3O_8, with preliminary estimates in the $50 per lb forward-cost category. Estimates in the higher forward-cost categories include, by definition, reserves in all lower cost categories.

ERDA has also compiled a uranium-mineral inventory, which is included in the 1977 uranium industry report (ERDA, 1977a). It lists inventories of U_3O_8 down to a minimum grade of 0.01 percent as estimated from company drilling data; it was included in response to requests from uranium users or buyers who wanted to know what was there regardless of production costs. ERDA figures show a post-production uranium inventory in the U.S. of 1,184,000 tons of U308, and in New Mexico of 493,000 tons. These figures compare with the U.S. reserves of 680,000 tons in the $30 per lb forward-cost category and with New Mexico reserves of 357,000 tons in the same category. However, the inventory includes property that cannot be exploited economically, and so it is not a substitute for reserve estimates.

Potential resources are normally divided into three categories: probable, possible, and speculative. Probable potential resources are those estimated to occur in known productive uranium districts; possible resources are those estimated to occur in undiscovered or partly defined deposits in formations or geologic settings productive elsewhere within the geologic province; speculative resources are those estimated to occur in undiscovered or partly defined deposits 1) in formations or geologic settings not previously productive, but within a productive geologic province or 2) within a geologic province not previously productive.

The uranium reserves for New Mexico, Wyoming, and other producing states are given in table 26 and illustrated in fig. 17. A net increase of about 40,000 tons of U_3O_8 in the $30 cost category since January 1976 raised U.S. reserves to 680,000 tons. Most of the net addition was due to substantial increases in the San Juan Basin reserves as a result of extensive exploration over the past several years. Estimates of $30 reserves in the Wyoming basins decreased somewhat because of production cost increases; however, the decrease represents material now included in the $50 per lb cost category. The ERDA estimate of $50 reserves nationwide is 840,000 tons.

The changes in potential resource estimates in the $30 cost category during 1976 amounted to a slight increase in probable potential and to decreases in the possible and speculative classes. Decreases can be the result of either conversion of material to reserves or of cost increases that place recovery costs beyond the highest cost-per-lb category.

For the first time preliminary estimates were made of potential resources in the $30 to $50 cost increment. Table 27 lists the ERDA current estimates of potential resources with the reserve figures and by-product recovery estimates included to give the entire resource picture.

New Mexico's proven reserves in the lower forward-cost categories exceed those of any other state. Mining

TABLE 25—STATUS OF URANIUM PRODUCTION FACILITIES IN GRANTS REGION.

	Mill capacity (tons ore/day)[1]				
Company	1976	1977	1978	1979	1980
Anaconda	2,500	2,500	4,600	6,000	6,000
Kerr-McGee Corp.	7,000	7,000	7,000	7,000	7,000
United Nuclear-Homestake Partners	3,400	3,400	3,400	3,400	3,400
Reserve Oil & Minerals/Sohio	--	1,600	1,600	1,600	1,600
United Nuclear Corp. (Church Rock)		2,000 (2nd half)	2,000	2,000	2,000
Gulf Mineral Resources Co.					2,500[2]
Total	12,900	14,500 (1st half) 16,500 (2nd half)	18,600	20,000	22,500

1. Data from uranium mining industry
2. Capacity ultimately going to 5,000 tons ore/day

TABLE 26—Distribution of uranium ore reserve by state as of January 1, 1977 (source: ERDA, 1977a).

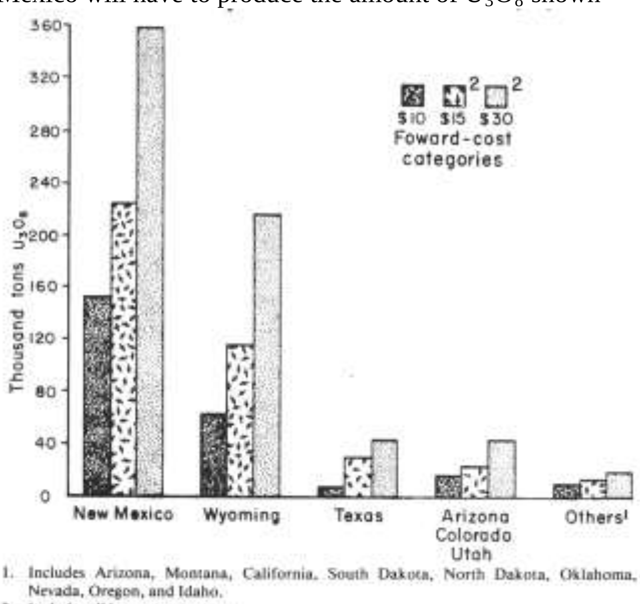
State	Tons ore	% U_3O_8	Tons U_3O_8	% Total tons U_3O_8	Number of deposits
			$10 Reserves		
New Mexico	55,800,000	0.27	152,700	61	70
Wyoming	55,400,000	0.11	62,300	25	56
Texas	6,200,000	0.12	7,300	3	37
Ariz., Colo., & Utah	5,800,000	0.30	17,300	7	288
Others[1]	5,800,000	0.18	10,400	4	75
Total	129,000,000	0.19	250,000	100	526
			$15 Reserves[2]		
New Mexico	120,000,000	0.19	225,500	55	112
Wyoming	111,400,000	0.11	116,300	28	143
Texas	49,300,000	0.06	29,000	7	107
Ariz., Colo., & Utah	12,700,000	0.19	24,700	6	793
Others[1]	11,600,000	0.13	14,500	4	214
Total	305,000,000	0.14	410,000	100	1,369
			$30 Reserves[2]		
New Mexico	327,900,000	0.11	357,000	53	175
Wyoming	307,700,000	0.07	216,500	32	265
Texas	87,600,000	0.05	44,000	6	132
Ariz., Colo., & Utah	39,000,000	0.11	43,000	6	982
Others[1]	23,800,000	0.08	19,500	3	247
Total	786,000,000	0.09	680,000	100	1,801

1. Includes California, Idaho, Montana, Nevada, North Dakota, Oklahoma, Oregon, South Dakota, and Washington
2. Includes all lower cost reserves

company representatives have stated that the San Juan Basin in New Mexico is one of the most favorable places in the U.S. for further uranium exploration. Because uranium may be considered a "locatable mineral" under the 1872 mining law, no environmental impact statement is necessary prior to development of mines on Federal land.

Future U308 requirements

As noted, New Mexico was supplying 46 percent of the nation's U_30_8 production throughout 1976. If that percentage of the market is to be maintained, then New Mexico will have to produce the amount of U_3O_8 shown



1. Includes Arizona, Montana, California, South Dakota, North Dakota, Oklahoma, Nevada, Oregon, and Idaho.
2. Includes all lower cost reserves.

FIGURE 17—Distribution of U_3O_8 reserves by state in the three forward-cost categories (source: ERDA, 1977a).

TABLE 27—Tons of U_3O_8 resources in U.S. as of January 1, 1977 (source: ERDA, 1977a).

Forward-cost category ($/lb)[1]	Reserves	Potential resources: Probable	Possible	Speculative
10	250,000	275,000	115,000	100,000
10-15 increment	160,000	310,000	--	--
15	410,000	585,000	490,000	190,000
15-30 increment	270,000	505,000	630,000	290,000
30	680,000	1,090,000	1,120,000	480,000
30-50 increment	160,000	280,000	300,000	60,000
50	840,000	1,370,000	1,420,000	540,000
By-product recovery[2]	140,000	--	--	--
Total	980,000	1,370,000	1,420,000	540,000

1. Each cost category includes all lower cost reserves or resources
2. Estimated by-product from phosphate and copper production

in table 28. It is informative to compare the demand with the reserves (table 26) and the resources (table 27) for New Mexico. The United States demand in table 28 is based on data from ERDA (1977a).

At present over 90 percent of the uranium produced in the U.S. is purchased by the electric utility industry. The remainder goes for export, research, and miscellaneous radiological applications. In essence, then, an analysis of the uranium-producing industry becomes an analysis of the nuclear generating industry.

There are currently 63 nuclear electric generating units in operation in the U.S. with a net output of 45,451 MWe (megawatts electric). This constitutes nine percent of present U.S. generating capacity. In addition to these, there are 69 units under construction and another 75 on order. This will bring the total number of units to 207 and will represent about 200,000 MWe (net) of generating capacity (ERDA, 1977b). Each additional 1,000 MWe plant requires 600 tons of U_30_8 for an initial reactor core; therefore, the 155,000 MWe increase represented by plants under construction or on order will require 155 times 600 or 93,000 tons U_30_8 just to start up. Many of the mines now under development in New Mexico, Wyoming, and elsewhere are beginning operations in anticipation of that demand.

TABLE 28—Projected U.S. U_3O_8 demand for nuclear power growth, and demand on New Mexico resources (no plutonium recycle).

End year	U.S. U_3O_8 demand[1] (thousand tons) Annual	Cumulative	New Mexico demand to maintain 46% of U.S. production (thousand tons) Annual	Cumulative
1977	12.3	12.3	5.7	5.7
1978	19.8	32.1	9.1	14.8
1979	24.4	56.5	11.2	26.0
1980	28.6	85.1	13.2	39.1
1981	32.3	117.4	14.9	54.0
1982	36.1	153.5	16.6	70.6
1983	35.5	189.0	16.3	86.9
1984	41.3	230.3	19.0	105.9
1985	39.9	270.2	18.4	124.3
1986	41.2	311.4	19.0	143.2
1987	44.5	355.9	20.5	163.7
1988	43.4	399.3	20.0	183.7
1989	44.2	443.5	20.3	204.0
1990	45.1	488.6	20.7	224.8

1. Enrichment feed contracts 208,000 megawatts electric; 0.20 percent tails to October 1980; 0.25 percent tails thereafter; ERDA, 1977a

Not all of those 207 units will be on line by 1985. ERDA is currently projecting 172 units by that date, down from 177 units projected in October 1976. The net electrical output from the 172 units will be approximately 163,000 MWe, which is 3.5 times the current nuclear capacity. This in turn could indicate nearly 3.5 times the current U3O8 requirements by 1985, necessitating annual U.S. production of approximately 40,000 tons; if New Mexico is to keep pace, nearly 20,000 tons per year from this state's reserves would have to be produced.

Even with the continued downward revisions in ERDA's projections of nuclear generating capacity by 1985, domestic U3O8 requirements are going to remain high. The cumulative demand for the 1975-1985 period has been estimated by the mining industry to be 200,000 tons. ERDA figures show 488,600 tons cumulative needed by 1990 to fill enrichment plant feed contracts (table 28). Unless imports constitute a significant portion of this, it becomes obvious that the present U.S. reserve base of 680,000 tons U3O8 (table 26) will be nearly depleted by the mid-1990's.

Estimates are that 10-20 percent of U.S. uranium requirements will be imported during the next decade, but anything in excess of that is unlikely in the face of rising demand elsewhere in the Free World (Davis, 1977). Any further relief of the supply-demand situation will have to be sought in the area of uranium-plutonium recycle of spent light-water reactor fuel.

Uranium fuel cycle and demand for raw uranium

Other than the level of commitment to nuclear fission energy, there are a number of other factors that can and will moderate or stimulate demand for raw uranium and in turn affect the economics of that industry in New Mexico. These are 1) enrichment plant tails assay, 2) plutonium and uranium recycle, 3) progress in the development of the LMFBR (liquid metal fast breeder reactor), and 4) to a limited extent, nuclear plant capacity factor.

Enrichment plant tails assay

Essentially all commercial nuclear power reactors in use in the U.S. are LWR's (light-water reactors). In this type of reactor, only "normal" water is used as the moderator in the reactor core. A moderator is necessary to slow down fission neutrons so that they may be more easily captured by the U-235 isotope, a capture that usually results in immediate fission with the release of nearly 200 million electron volts (Mev) of energy. LWR's are usually designed so that they require uranium to be enriched to 2.8-4 percent U-235. Natural uranium contains only 0.71 percent U-235 (the rest being essentially U-238); therefore, the U-235 content must be increased in order for it to be suitable as reactor fuel. This increase is presently accomplished in government-owned enrichment plants, which all employ the same basic process called gaseous diffusion.

The gaseous diffusion plant technology was develped in the early 1940's for weapons manufacture and results in the production of two gas streams, one enriched and the other depleted in U-235. The depleted stream is containerized and stored for possible future use in the LMFBR. The enriched stream, after as many as 1200 stages of diffusion, emerges containing between 2.8 and 4 percent U-235, depending upon contractual agreement.

In enrichment plant terminology, energy expended in isotopic separation is quantified in terms of SWU (separative work units). An SWU is a way of expressing in a single number the isotopic separation effort or energy involved. It quantifies the enrichment effort by weighting the three factors of plant flow rate, product assay, and waste or tails assay.

At the present time there are three enrichment plant facilities in operation—all government owned, but operated under contract by private corporations. At Oak Ridge, Tennessee, and at Paducah, Kentucky, the plants are operated by the Union Carbide Corporation; the plant at Portsmouth, Ohio, is operated by the Goodyear Atomic Corporation. Although they are located far apart geographically, the plants are operated on an integrated basis, with interplant shipments of material in gas cylinders. For instance, one plant may be better able to handle low assay feed, and so the waste streams from the other two would be shipped back to that particular plant for further processing. According to ERDA the varied degree of overlap afforded by this integrated mode of operation maximizes plant performance and capacity.

The weight percent of U-235 left in the depleted stream is referred to as the enrichment plant tails assay. The tails assay value selected for plant operation is dependent upon several factors; however, the basic factor is the rate of throughput of feedstock. In simplest terms, as the depleted stream goes to ever lower U-235 assay values, more work is required to separate the remaining U-235. It becomes obvious then, that with a given plant capacity, more U-235 can be separated using higher assay feedstock than by continuing to send progressively depleted waste streams through successive separative stages. An important effect, however, is that cutting off the enrichment process at a higher tails assay in order to increase total production results in more U-235 being wasted, or temporarily set aside, leading to a greater demand for raw uranium. Uranium requirements are 20 percent greater if the enrichment plants operate at 0.30 percent U-235 tails assay than if 0.20 percent is used (Hanrahan and others, 1976).

Table 29 shows U.S. uranium requirements at three different tails assays for the midcase (mode 1 and 2 will be discussed further on). This case merely assumes that 1) nuclear power will remain an economically competitive electricity source throughout the country, 2) some new technologies are implemented to help achieve a closed fuel cycle, 3) some conservation measures are successful, and 4) the average annual growth rate in electrical consumption will be 5.2 percent until 1985 and 4.5 percent between 1985 and 2000. The pre-1974 growth rate was 7 percent annually.

The midcase, being the most probable one, is the only one reproduced here. It clearly shows the effect of enrichment plant tails assay for both mode 1 and mode 2. ERDA is presently transacting with utilities at a tails assay of 0.20 percent U-235. The transaction tails assay

TABLE 29—FORECAST OF U.S. MIDCASE URANIUM REQUIREMENTS (source: Hanrahan and others, 1976).

Mode 1: Uranium and Plutonium Recycled on a Constrained Basis

	Thousands of short tons of U_3O_8					
	0.20% Tails		0.25% Tails		0.30% Tails	
Year	Ann.	Cum.	Ann.	Cum.	Ann.	Cum.
1976	11	11	12	12	13	13
1980	19	73	20	79	22	87
1985	31	200	34	220	37	240
1990	41	390	45	430	50	475
2000	65	925	71	1015	80	1130

Mode 2: Limited Uranium Recycle, Plutonium not Recycled in LWRs

	Thousands of short tons of U_3O_8					
	0.20% Tails		0.25% Tails		0.30% Tails	
Year	Ann.	Cum.	Ann.	Cum.	Ann.	Cum.
1976	11	11	12	12	13	13
1980	19	73	20	79	22	87
1985	36	220	39	240	43	260
1990	55	455	60	495	66	545
2000	82	1195	90	1300	99	1435

in effect specifies the amount of enrichment service the customer will purchase from ERDA and the quantity of natural uranium the customer will deliver to ERDA in order to obtain the required amount of enriched uranium. ERDA is at present actually operating its three gaseous-diffusion plants at a tails assay of 0.25 percent U-235. Although more natural uranium is required at higher tails assay, it is possible for ERDA to operate this way because government stockpiles of uranium can be fed to the plants to make up the balance. In this way ERDA can effectively increase enrichment plant production in order to fulfill contractual obligation. Since the government normally retains control of the tails (the customer seldom wants them), it has the option of further processing the tails at a later date, and anything recovered belongs to the government.

The major variable influencing the selection of the transaction tails assay in the future will be the amount of enriched uranium required to supply customers under ERDA contracts; the greater the requirements the higher the tails assay if additional enrichment plants are not built. These requirements will be directly influenced by the permissibility of using fissile plutonium recovered from spent fuel elements as a partial substitute for enriched uranium in LWR's.

Plutonium and uranium recycle

The fuel elements discharged from LWR's contain considerable amounts of residual fissile U-235 and Pu-239. Normally spent fuel elements will have as much as 0.9 percent (8-9 grams/kilogram uranium) U-235 and 0.6 percent (6 grams/kilogram uranium) Pu-239. The fissile plutonium isotope Pu-239 in the spent fuel rods is the result of irradiation of U-238 in the reactor core. Pu-239 is highly radioactive; because of its high energy value and the energy value of the residual U-235, it becomes logical to assume that recycling of plutonium in LWR's and recovery of U-235 for the enrichment plant are practical and desirable steps. In theory, from the standpoint of resource conservation and reactor-fuel economics, recycling and recovery are very desirable. In practice, however, the recovery process is expensive and fraught with difficulty. The processing of plutonium-bearing materials is dangerous and hazardous for a number of reasons: for example, the extreme toxicity of Pu-239, the criticality limitations, and the possible diversion of the materials to other than intended use. The extensive and elaborate shielding required for workers, the remote-handling capabilities, the high rate of disposal of contaminated supplies and equipment, and the extensive safeguarding provisions necessary make recycling a very costly operation. Capital investments are high; as a result, accurate timing is essential in the planning and construction of commercial plants.

Thus far, only one U.S. company has ventured into the business of spent-fuel reprocessing and become operational. Nuclear Fuel Services, Inc., operated a plant near West Valley, New York, from 1966 to 1972, when it shut down for modification and never reopened because of increasingly stringent regulations and deteriorating economics. Another company, Allied General Nuclear Services, nearly completed construction of a plant near Barnwell, South Carolina, but it never opened. Problems in meeting State and Federal regulations for the handling of radioactive materials and employee hazards plagued both plants.

The flow of materials in a recycle/recovery operation has been summarized by ERDA (1976b). The spent fuel elements are shipped to a reprocessing plant where the fuel assemblies are sheared into small pieces and the fuel removed from its cladding by dissolution. Next the uranium, plutonium, and fission product wastes are partitioned, purified, and concentrated by sequential solvent extraction. The uranium and plutonium liquids are then converted to UF_6 and PuO_2 respectively. It should be mentioned that Pu and U, being different elements, may be separated chemically with much less difficulty than that encountered in isotopic separation.

Recovered PuO_2 is then mixed with natural UO_2 for subsequent fabrication into LWR fuel elements, a step called mixed-oxide fuel fabrication that requires special shielding and remote-handling capabilities. The UF_6 is sent to the enrichment plant for subsequent fabrication into UO_2 fuel elements.

If and when reprocessing plants can be safely built and operated, there will definitely be a market for the products. Even in the event that the development of fast breeder reactors (which must have mixed-oxide fuel) is slowed or even halted, the fissile plutonium oxide may still be used, though less advantageously, in LWR's. In 1974 the AEC (Atomic Energy Commission) released a draft Generic Environmental Statement on the use of mixed-oxide fuel (GESMO, AEC, 1974) in LWR's, which states that: 1) the safety of light-water reactor operations would not be adversely affected. It concluded there is sufficient experimental work and demonstration of mixed-oxide fuel performance to warrant widespread commercial use. 2) The use of recycled plutonium can reduce the overall uranium requirement for nuclear fuel about 10 percent by 1990 and can subsequently reduce the environmental impact on natural resource consumption. The estimated cumulative energy equivalent of using recycled plutonium through 1995 is 10 billion barrels of oil or 2 billion tons of coal. 3) The radiological impact from the production of nuclear fuel would be reduced. 4) There are no safeguards-related issues which should delay a decision to permit use of plutonium in mixed-oxide fuel for light-water reactors, but widespread use of mixed-oxide fuels must be accompanied by decisions, within about a year, concerning stricter safeguard measures required for a mature plutonium recycle economy.

Referring again to table 29 (Hanrahan and others, 1976), the effect of uranium and plutonium recycle can be seen. Mode 1 assumes that the Allied-General Nuclear plant is completed and regulatory issues resolved so that operations begin during 1981 followed by routine operation at 1500 MT/year (metric tons per year), beginning in 1982. Recovered uranium and plutonium are recycled to LWR's soon after reprocessing unless the plutonium is required by the breeder program. Additional 1500 MT/year plants are available in 1985, 1988, and as required after 1990.

Mode 2 assumes that the recycle of plutonium in light-water reactors is deferred indefinitely. The Allied-General Nuclear plant is put into operation in a pilot-plant mode during 1985 and operates at 1000 MT/year beginning in 1986. The nominal quantities of recovered uranium are recycled in LWR's, but plutonium is utilized only in fast breeder reactors. To provide the plutonium required by breeders, additional 1500 MT/year reprocessing plants must be added in 1997 and 2000.

Clearly, from the standpoint of resource conservation, uranium and plutonium recycling is highly desirable. Without recycling, uranium demand will be greater and uranium prices higher. However, since the 1974 AEC statement, President Ford has stated his policy decision regarding this matter. On October 28, 1976, President Ford announced:

> Reprocessing and recycling of plutonium should not proceed unless there is sound reason to conclude that the world community can effectively overcome the associated risks of proliferation. . . . Avoidance of proliferation must take precedence over economic interests. . . . The U.S. and other nations can and should increase their use of nuclear power for peaceful purposes even if reprocessing and recycling of plutonium are found to be unacceptable. The U.S. should no longer regard reprocessing of spent nuclear fuels to produce plutonium as a necessary and inevitable step in the nuclear fuel cycle. We should pursue reprocessing and recycling in the future only if they are found to be consistent with our international objectives.

This cautious approach has since been overshadowed by President Carter's decision to cut off funding for development of breeder reactors and a refusal to consider nuclear fuel reprocessing plants.

Liquid metal fast breeder reactor

The LMFBR is so named because it uses a molten metal, usually sodium, in the heat transfer loop or loops between the reactor coolant system and steam system that drives the turbines. A liquid metal was chosen because it does an excellent job of neutron conservation, is a good heat transfer agent, and—unlike steam—does not have to be highly pressurized to achieve high temperatures. One of the less desirable features of the molten sodium, however, is its highly reactive chemical nature.

The breeder part of the name refers to the fact that this reactor has the potential for producing (breeding) more fuel than it consumes. It does this by using mixed-oxide fuel, which is composed of Pu-239 and U-238.

The enriched uranium fabricated into fuel rods for LWR fuel contains perhaps 3.2 percent by weight of the fissionable isotope U-235; the remainder is essentially U-238. Although U-238 cannot be fissioned by the slow thermal neutrons that cause U-235 to fission, it may nevertheless capture neutrons. When U-238 molecules make such a capture, a reaction called beta minus decay (resulting in the ejection of an electron from the nucleus) leads to the formation of Pu-239, which is fissionable by slow neutrons (Weidner and Sells, 1973).

The recognition of these reactions led to the development of the breeder reactor. In the breeder there are two fuel materials, one fissionable (Pu-239) and the other fertile (U-238) in the sense that it can be converted into fissionable material in the reactor. In the fission of Pu-239 there are, on the average, three neutrons released: one of these must maintain the chain reaction by causing a Pu-239 nucleus to fission and at least one must be captured by U-238, forming Pu-239, to maintain the same amount of fissionable fuel in the reactor. If the remaining neutron is also captured by U-238, the reactor can then "breed" fissionable Pu-239; in other words, if the reaction is properly controlled, more fissionable material is produced than consumed.

The impact of the breeder reactor on uranium demand is obvious: if the relatively abundant non-fissionable U-238 isotope could be used, the demand for uranium ore would be reduced. Known reserves of low-cost uranium ore are very limited, and, without the breeder reactor, a nuclear fuel crisis is likely by the mid-1990's.

By taking advantage of the concept of the fast breeder, the nation should be able to extend its use of uranium reserves from decades to perhaps centuries (AEC, 1974). Among other things the breeder would allow utilities to use enrichment plant tails now stored in steel cylinders at various government sites. These cylinders contain over 200,000 tons of uranium depleted in the U-235 isotope; in the breeder this uranium could be equivalent to the energy contained in over 400 billion tons of coal (Lapp, 1975).

The obvious and only economical source of Pu-239 for LMFBR's is the plutonium contained in LWR spent-fuel elements. The Pu-239 contained in 11 annual discharges of a 1,000 MWe LWR is sufficient to provide fuel for one 1,000 MWe LMFBR initial core (ERDA, 1976b). Five additional annual LWR discharges are required to provide enough Pu-239 for the first LMFBR reload. If after this first reload the breeder achieves self sufficiency, the introduction rate of breeder generating capacity would still be dependent on U.S. capacity to recover plutonium in reprocessing plants; hence the importance of the Barnwell, South Carolina, plant and a western U.S. plant located perhaps at a waste repository site.

Other factors complicate the above figures and tend to reduce the availability of plutonium: namely, a cooling period of 1-5 years for spent fuel, the buildup of higher isotopes of plutonium, and the loss of plutonium during reprocessing. The economics of scale for reprocessing plants also remains to be worked out, but rigorous planning on these matters must await the development of a demonstration LMFBR to establish the feasibility of this type of reactor.

Nuclear plant capacity factor

Utility companies will order nuclear plants of a specifically rated capacity, such as 750 MWe or 1,000 MWe. This means that when that plant is completed and running at 100 percent capacity, it will be generating power at the specified rated capacity.

The capacity factor, on the other hand, takes into account plant down-time to "wring out bugs," to refuel or rearrange fuel elements, or to perform routine maintenance or repair work. For instance, if a plant is down for 36 days per year, or 10 percent of the time, but operates at 100 percent capacity the rest of the time, it would have a capacity factor of approximately 90 percent. This is unrealistically high, however, even for coal-fired plants.

ERDA has stated that capacity factors for nuclear plants have not measured up to what utility companies expected when they ordered the plants or when they originally contracted for enrichment plant services (Hanrahan and others, 1976). Utility companies often did their planning on the basis of 80 percent or higher capacity factors. ERDA now assumes that nuclear plants will operate at a 70 percent factor under equilibrium conditions, which means a corresponding decrease in fuel requirements. Pre-equilibrium operation consists of a short period (less than one year) at 40 percent followed by two years at 65 percent. It is further assumed that the capacity factor at each plant will decline two percentage points per year after the 15th year of operation, to a minimum of 40 percent, at which point the plant will be shut down and dismantled. Useful life of a plant is expected to be no more than 40 years.

According to Perl (1976), however, nuclear capacity factors have averaged slightly under 60 percent during the last five years but show a tendency to increase somewhat with age, at least over the first 10 years of operation. The data used also indicated that initial capacity factors are somewhat lower for large plants than for smaller ones. A 500 MWe nuclear plant would be expected to have an initial capacity factor of 63 percent, rising to 78 percent after eight years. A 750 MWe plant may go from 55 percent to 70 percent over the same time period and a 1,000 MWe plant from 47 percent to 62 percent.

Assuming that 62 percent capacity factor is the maximum achieved by a 1,000 MWe plant and that according to ERDA the capacity factor begins to drop two percentage points per year after the 15th year of operation, it would take only 11 years to drop the capacity factor 22 percent to the 40 percent minimum. In this case it would mean retiring the plant after 26 years. Simple calculations show that in order for a plant to remain in operation for 40 years with a 2 percent decrease in capacity factor for each year beyond the 15th, a maximum of 90 percent capacity factor would have to be achieved for the 15th year. Ninety percent is unrealistic at the present time, and so either the annual decrease in capacity factor will have to be improved upon or the plant will have to be retired at a younger age.

This is all highly speculative because there is no data available for large plants after the first 10 years of operation. Many utility companies do not seem concerned about the present lower capacity factors of the large plants, since a significant number of those under construction are 1,200-MWe-rated capacity or above.

Geothermal energy

by K. S. Hatton, *Office of the State Geologist*

Location of major geothermal areas

The three principal geothermal areas in New Mexico are located along the Rio Grande rift and in the west-central and southwestern portions of the state. Associated with the Rio Grande rift are the Valles Caldera and Jemez Hot Springs in Sandoval County, Ojo Caliente in Taos County, Socorro Peak in Socorro County, Truth or Consequences thermal area in Sierra County, and Radium Springs and Kilbourne Hole in Doña Ana County.

The portion of the west-central geothermal area with the greatest terrestrial heat-flow value lies in the southwest corner of McKinley County. The southwestern geothermal area comprises the Lower Frisco system in Catron County, Gila Hot Springs and Mimbres in Grant County, and the Lightning Dock area (Animas "Hot Spot") in Hidalgo County. Heat-flow maps of these areas can be found in Reiter and others (1975). In a recent report, Stone and Mizell (1977) have summarized the location and natural setting of the geothermal target areas as well as the status of geothermal exploration in the state.

Leasing activity

On May 25, 1977, the BLM called for competitive bids on 17 parcels of land in the Baca Location No. 1 KGRA (Known Geothermal Resource Area) in Sandoval and Rio Arriba Counties. Bids were received and granted for 11 of these parcels, which cover 18,050 ac; bonus bids totaled $574,425.

As of September 15, 1977, the BLM had issued 97 currently active geothermal leases covering 158,964 ac of national resource land in New Mexico. Sixty-eight of these leases, comprising 117,766 ac, were issued after non-competitive bidding; 29, comprising 41,199 ac, were issued after competitive bidding.

On September 20, 1977, the BLM called for competitive bids on 17,968 ac consisting of five parcels in the Radium Springs KGRA, one parcel in the San Ysidro KGRA, and six parcels in the Baca Location No. 1 KGRA. The BLM scheduled the Socorro Peak KGRA lease sale for November 17, 1977, and the Lower Frisco KGRA and Gila Hot Springs KGRA sale for May 24, 1978.

As of June 30, 1977, the New Mexico State Land Office had issued a total of 185 currently active geothermal leases covering 78,579 ac. This past year (1977) the State Land Office made an evaluation of its leasing program and tentatively scheduled a statewide lease sale for late November 1977.

Recent exploration

From January through June 1977 the NMOCC approved 89 temperature gradient wells; 14 applications are pending. Three development wells were approved; one application is pending. Union Oil Company of California, Sunoco Energy Development Company, Chevron Oil Company, Amax Exploration, Inc., and Aminoil, U.S.A. will drill these wells on State and private land in New Mexico. Drilling will be concentrated in the Socorro Peak-Magdalena area, the Animas Basin, the Radium Springs area, and along the Jemez River from Jemez Springs to San Ysidro.

In March 1977 the U.S.G.S. granted permission to Amax Exploration, Inc. to drill four temperature-gradient wells in the Lightning Dock area. An application is pending from Phillips Petroleum Company to drill seven temperature-gradient wells in the Baca geothermal area.

Research and development

Union Oil and the Public Service Company of New Mexico have announced plans for a cooperative development of Union's geothermal leases in the Valles Caldera. The companies anticipate constructing a 50 MWe electrical generating facility as a demonstration plant. Such a plant could supply the electrical needs of a city the size of Santa Fe. A proposal for partial funding has been submitted to ERDA. If the demonstration plant proves commercially feasible, a 400 MWe development may be built.

In the spring of 1977, LASL (Los Alamos Scientific Laboratory) successfully completed a connection in the fracture system of the Hot Dry Rock Geothermal Energy Project at the Fenton Hill site, west of the Valles Caldera. LASL plans to conduct a 10 MW (thermal) heat-extraction experiment in September 1977. When two 5 MW (thermal) modules have been installed, water will be circulated through the fracture system for several months to determine the chemical, mechanical, and physical properties of the reservoir and heat-exchange system. If the results of this procedure are favorable, LASL will attempt a 100 MW (thermal) heat-extraction experiment that could contribute valuable information toward the design and construction of small-scale hot dry rock electric generating plants. A conservative estimate is that 100 MW (thermal) could potentially produce about 10 or 15 MW (electrical). Because LASL's hot dry rock energy production method does not require the presence of a naturally occurring hot water reservoir, scientists from countries lacking such reservoirs have shown interest in the hot dry rock project. An agreement has been formalized between the Italian National Electrical Agency and LASL for cooperation on this type of geothermal research. Italian engineers studied various aspects of the Fenton Hill project in New Mexico during the summer of 1977, and an exchange group of LASL scientists will soon leave for Italy.

West Germany, which may also become a close participant in the hot dry rock project, has sent observers to Fenton Hill and offered substantial funding assistance. The hot dry rock method is thought to be the only kind suitable for development in West Germany. Representatives from Switzerland have also expressed an interest in cooperative efforts to map and develop hot dry rock areas in Europe.

Meanwhile, ERDA-funded research on drill bits at Sandia Laboratories is continuing. Development of the spark drill, the terra drill, and the continuous chain bit is taking place under the sponsorship of ERDA's Division of Geothermal Energy; and of the Compax bit, under the Division of Oil, Gas, and Shale Technology.

Recent legislation

On May 6, 1977, ERDA awarded the first geothermal loan guaranty, which covered $9,030,000 for a loan by the Bank of America (Los Angeles) to Republic Geothermal, Inc., Santa Fe Springs, California. The corporation plans to construct a geothermally powered electric generation plant. This figure comprises 75 percent of the estimated total cost of a drilling project in the East Mesa area of California's Imperial Valley. ERDA's Geothermal Loan Guaranty Program was authorized by the Geothermal Research, Development, and Demonstration Act of 1974 (Public Law 93-410).

One of the several proposed amendments to this law would pledge the "full faith and credit" of the U.S. Government to the honoring of guaranties. Other amendments would provide for 75 percent total cost coverage of direct thermal use projects and for "interest differential payments for guaranties on taxable borrowing by states, municipal utilities, or other political subdivisions of states, or Indian tribes."

Several other recent developments at the Federal level have great potential for helping the geothermal industry. President Carter's National Energy Plan proposes a tax deduction for intangible drilling and development costs comparable to deductions now available for oil and gas drilling. The plan further recommends that additional funding be provided to assist in the location of new hydrothermal sources for near-term electrical generation and direct thermal use. The President favors Federal support for "demonstration of direct, non-electric uses of geothermal energy for residential space conditioning and industrial and agricultural process heat in areas where this resource has not previously been exploited."

Another bill, "The Geothermal Steam Act Amendments of 1977," would increase the per state acreage limitation on geothermal leasehold from 20,480 to 51,200 and assure geothermal leaseholders access, on an equitable basis, to any transmission lines or rights-of-way for transmission lines on public lands in the general area of their leasehold.

Feasibility of heating and cooling State buildings

This interim report was prepared in response to Senate Joint Memorial 2, a bill introduced and passed by the 33rd New Mexico Legislature, requesting that the New Mexico Energy Resources Board assess the feasibility of geothermally heating and cooling the Capitol complex in Santa Fe and other State-controlled facilities. This study will pinpoint and tentatively evaluate those areas of the state that possess a significant number of geothermal indicators and are located sufficiently near State buildings.

The question of solar vs. geothermal energy, not discussed here, should of course be considered in any final decision on geothermal feasibility.

Each geothermal area in New Mexico is unique and complex and must be assessed individually from both the geological and economic standpoint. This report considers only those areas having 1) relatively high temperature; 2) relatively shallow depth; 3) a reservoir with adequate porosity, permeability, and water; and 4) sufficient proximity to State buildings for the hot water to deliver enough heat after being transported.

To cool a building with geothermal waters requires a much higher water temperature than to heat it. Thus, heating may be feasible in some places where cooling is not. Electrical generation also requires far higher temperatures than are needed for the warming of space. Further, basic economic assumptions vary. For example, some authorities believe that a good limit for piping water of about 170° F would be about 20 mi, whereas others hold that a distance of 13 mi is too far for geothermal heating. For all locations mentioned in this report, questions of feasibility and range of geothermal applications can be fully answered only after actual drilling and testing of the reservoirs and careful consideration of piping distances, terrain difficulties, desired pressures, and other factors.

The following areas possess a sufficient number of geothermal indicators to warrant further exploration for direct heating and, possibly, cooling applications and are at the same time located sufficiently near to State facilities.

Jemez Mountains

Most researchers consider the best geothermal area in the state to be the land in Sandoval County encompassing the Baca Location No. 1 KGRA, the Fenton Hill site, Jemez Hot Springs, and the San Ysidro KGRA. The most significant geothermal developments in New Mexico have occurred in this area. These are the Union Oil Company of California's steam wells in the Valles Caldera and the Fenton Hill project, which is the hot dry rock operation conducted by LASL.

A State-controlled group of buildings, the Los Alamos public school system, is within five miles of the Baca Location No. 1 KGRA boundary and within the boundaries of the much larger area designated by the U.S.G.S. as prospectively valuable for geothermal resources. Because the cost of heating and cooling the public school buildings in Los Alamos now amounts to about $137,000 per year, initiation of feasibility studies for the geothermal heating and possibly cooling of state installations there would seem worthwhile. A LASL committee now studying alternative heat and electricity sources for the Laboratory's own use is considering geothermal energy.

The public school system in Cañones, nine miles south of the Jemez Hot Springs, spent about $33,530 last year on gas heating; this system seems to offer another good possibility for conversion to geothermal energy. A Buddhist religious colony in the village of Jemez Springs presently heats a greenhouse geothermally.

Lightning Dock KGRA

The Lightning Dock KGRA in the Animas Valley, Hidalgo County, is the next most highly developed geothermal area. Much drilling has been done, and a considerable amount of State, Federal, and private land leased. This area, like the Jemez Mountains area, has been the subject of a great deal of study. Recent work suggests that thermal waters ascend in a conduit-like structure. Geophysical measurements near the wells may have probed a deep hydrothermal reservoir.

Lordsburg, about 12 mi from the Lightning Dock KGRA, is thought to be within an economical distance for geothermal application. Since this field is believed to have a sufficiently high reservoir base temperature for the development of geothermal electricity, it may be possible to use the same hot water for both electrical generation and the heating of buildings. The Lordsburg public schools now spend about $19,500 per year on gas heat.

Las Cruces

Las Cruces is near several areas that may have good geothermal potential; the city contains many State-controlled buildings, notably those belonging to New Mexico State University and the Las Cruces public school system. The public schools spent about $106,570 last year on heating. New Mexico State University's gas bill for the next fiscal year is expected to be between $450,000 and $600,000 owing to the recent sharp rise in gas costs in the Las Cruces area. The electric bill for cooling was not figured separately from the total electric bill, but it is estimated to have been between $220,000 and $400,000 for the last fiscal year.

Kilbourne Hole KGRA, Radium Springs KGRA, and the Las Alturas area may all prove feasible as sources of hot water for space heating in Las Cruces. Because there is much information still to be gathered from these sites, no statement on the superiority of any one area will be made.

The Kilbourne Hole KGRA, which is being extensively studied and tested by private industry for electrical-generation potential, is a possible source of geothermal heating for Las Cruces. Possibly, fewer environmental problems would be encountered at this location than at Las Alturas because of its greater distance from town, but consequent higher piping expenses might negate this advantage.

Radium Springs KGRA, although believed to have a high reservoir base temperature, meets with divided opinions among the researchers in the field. The main reservations some researchers have about this area is that the size of the water reservoir is not known, and some assume it to be small. The two most fundamental questions, the location of a large thermal fluid reservoir and the nature of the heat source, have not been answered. Both of these questions involve deeper probing, perhaps to several kilometers (D. G. Brookins and others, in progress). A possible further disadvantage to geothermal development in the Radium Springs area is the division of much of the resource land into small parcels, each privately owned by different individuals. If further studies show the reservoir to be extensive, however, this area may afford a good possibility for geothermal heating in Las Cruces.

The Las Alturas area, a geothermal region adjacent to land owned by New Mexico State University, is now the subject of a geothermal application feasibility study by N. N. Gunaji and others (in progress) attempting to determine the degree, if any, to which the area may meet the heating, cooling, and electrical power needs of the New Mexico State University campus. Information is being gathered on the thickness and bounds of the aquifer in order to arrive at an estimate of the amount of energy available. Water temperature is expected to be in the 176 °-428 ° F range. Actual water temperature, however, and the depth at which that temperature might be found can only be proven by drilling. A proposal has been submitted to ERDA for funds to assist New Mexico State University in drilling a deep test well. In conclusion, the Las Cruces area appears highly favorable from the geological point of view and merits continued study.

Socorro

The New Mexico Institute of Mining and Technology in Socorro owns land that is a possible geothermal source area about two miles from the campus. This land is in the Socorro Peak KGRA that surrounds the city of Socorro, with the greatest areal extent being to the west and south of the city.

The New Mexico Institute of Mining and Technology is conducting an economic, technical, and environmental feasibility study to determine whether or not, given ideal resource characteristics, this source could efficiently supply space heating, water heating, cooling, and electrical power to the campus and community (A. R. Miller, in progress). Feasibility for heating the campus with geothermal waters, if an ideal source is found, appears favorable to some researchers. Here, as elsewhere, geothermal air conditioning may be less practical than space cooling by electrically powered evaporative units.

The Socorro area presents several characteristics tending to suggest the presence of a good geothermal source. The region possesses one of the highest heat-flow values in the state and is underlain by an extensive magma body at a depth of about 11 mi. Considerable geological and geophysical data is available on the location, size, shape, and depth of this magma body. Several smaller magma bodies appear to lie about 2.5 mi below the surface. Evidence that magma continues to be replenished in the area has been found in a deeply penetrating structure zone along the edge of the caldera. In addition, three important factors for a good geothermal reservoir are believed to be present: a good source of water, permeable rocks, and an impermeable caprock to protect the heated waters from cooling by surface waters. Detailed geologic mapping surveys are in progress, and enough is known about the controlling geologic structure and stratigraphy to designate the best drilling locations.

Private industry has shown a great deal of interest in the Socorro area. Four major companies are now exploring the area and drilling shallow holes to measure heat-flow values.

Truth or Consequences

Studies made of the T or C (Truth or Consequences) area suggest a high reservoir base temperature. Researchers are awaiting the collection of more detailed hydrologic and geochemical data, however, before stating firm conclusions on the area's geothermal potential (D. G. Brookins and others, in progress). Considerable state geothermal resource lands in the region have been leased to private interests (Stone and Mizell, 1977).

There are at least two State-controlled institutions in the T or C area that could greatly benefit from geothermal space heating: the public schools, which spent about $19,800 last year on heating bills, and the Carrie Tingley Hospital, whose heating bill last year was $20,662. The hospital is less than a mile from one of the natural hot springs. Several buildings in the city have been heated geothermally for many years.

Albuquerque-Belen

Conversion to geothermal space heating for the numerous State-controlled buildings in the Albuquerque-Belen area could, if feasible, save the State large sums of money, but little is presently known about the practicality of geothermal application in this region.

The University of New Mexico and the New Mexico State University are presently engaged in a study to determine the geothermal potential of the Albuquerque region. This study notes recently active volcanism and alignment of volcanic centers parallel to the Rio Grande rift boundaries, suggesting the possibility of heat sources at shallow depths in the earth's crust. No active hot springs are known, but geothermal waters may be present at depth. Surveys to be conducted in the later stages of this project are expected to give more information about these deep waters (D. G. Brookins and others, in progress). The New Mexico State University plans to begin a related project near Albuquerque this fall. During the last several years the Shell Oil Company drilled five deep oil test wells within 20 mi of Albuquerque. Temperatures as high as 374 ° F were reported at a depth of about 16,000 ft in one of these wells. A considerable quantity of water was found to occur in shallower zones in the Tertiary formations where temperatures were lower. Porosities in the deeper zones were found to be quite low, and only a minimal amount of water was recovered from testing. Any further determination of geothermal potential in the Albuquerque area must await further research and exploration.

Santa Fe

Experts in the geothermal field agree almost unanimously that the likelihood of finding an economically useful geothermal source in the Santa Fe area is virtually nil. Furthermore, none of the abundant data on water wells in Santa Fe, or any other evidence, indicates the presence of a geothermal source in this area. This office knows of no temperature-gradient studies indicating that Santa Fe has a higher than average temperature gradient. Various exploration tools and methods would have to be employed in an intensive search for a heretofore hidden heat source; and, prior to the initiation of drilling, geophysical surveys would have to be undertaken to determine the most favorable drilling site. These surveys, as well as any drilling, would be expensive and time consuming.

The nearest known site to Santa Fe having even slightly higher than normal heat-flow values is the Buckman well field which lies about 20 mi northwest of the Capitol in Santa Fe and supplies part of the city water. In this field there is as yet only an indication of intermediate, not high, gradients. The Buckman field is thought by some to be underlain by fairly recent volcanics; how far this heat source might extend to the east toward Santa Fe is not known. There is no reason to suppose that geothermal heat could economically be supplied from the Buckman area to buildings in Santa Fe or that exploration will turn up any heat source at shallow enough depths or close enough to the city to be economically useful.

In the future other areas of the state may be shown to have geothermal space-heating potential. The Mt. Taylor region is now under study and could possibly supply geothermal energy to the city of Grants. Another area that may have hot dry rock potential lies in the Zuni Mountains near Gallup.

Cost estimates on the installation of new heating and cooling systems, conversion of old systems, and piping from the source are relatively easy to obtain; but critical data on the amount of corrosive and pipe-clogging elements in the geothermal water, the temperature of the water, the influence of cooling meteoric waters, and the efficiency of the geothermal heat source can be obtained only after drilling. Some of this information can be obtained from economic and geologic studies either completed or now in progress, such as those funded by private industry, the New Mexico Energy Resources Board, the U.S.G.S., and ERDA.

Further research and drilling remain to be carried out before the feasibility of using geothermal energy in any given location can be definitely established.

Geothermal projects funded by ERB

Completed

Oxygen isotope geochemistry and geothermal energy potential in New Mexico
Principal investigator: Gary P. Landis, Dept. of Geology, University of New Mexico

Geothermal gradient measurements
Principal investigator: Marshall Reiter, New Mexico Bureau of Mines and Mineral Resources and Dept. of Geoscience, New Mexico Institute of Mining and Technology

Investigation of thermal regime of Rio Grande rift and neighboring provinces by employing very deep heat-flow measurements and establishing a crustal radiant heat generation
Principal investigator: Marshall Reiter, New Mexico Bureau of Mines and Mineral Resources and Dept. of Geoscience, New Mexico Institute of Mining and Technology

Seismic investigation of magma layer in crust beneath Rio Grande rift near Socorro, New Mexico (and relation to geothermal energy potential of region)
Principal investigator: Allan R. Sanford, Dept. of Geoscience, New Mexico Institute of Mining and Technology

Geothermal equipment
Principal investigator: Chandler Swanberg, Depts. of Earth Sciences and Physics, New Mexico State University

Geothermal investigations in southwest New Mexico
Principal investigator: Chandler Swanberg, Depts. of Earth Sciences and Physics, New Mexico State University

In progress

Engineering methods for predicting productivity and longevity of hot dry rock geothermal energy reservoir in the presence of thermal cracks

Principal investigator: Y. C. Hsu, Dept. of Mechanical Engineering, University of New Mexico

Evaluation of geothermal potential of the Basin and Range province of New Mexico
Principal investigators: Douglas G. Brookins, Jonathan F. Callender, Wolfgang E. Elston, George A. Jiracek, Albert M. Kudo, Gary P. Landis, and Lee A. Woodward, Dept. of Geology, University of New Mexico, and Chandler A. Swanberg, Depts. of Physics and Earth Sciences, New Mexico State University

Seismic exploration for shallow magma bodies in the vicinity of Socorro, New Mexico
Principal investigator: Allan R. Sanford and John W. Schlue, Dept. of Geoscience, New Mexico Institute of Mining and Technology

Geological investigation of the Socorro geothermal area
Principal investigator: Charles E. Chapin, New Mexico Bureau of Mines and Mineral Resources

Geothermal application feasibility study for the New Mexico State University campus
Principal investigators: Narendra N. Gunaji, Dept. of Civil Engineering, A. G. Walvekar, Dept. of Industrial Engineering, Leo LaFrance, Dept. of Mechanical Engineering, E. Thode, Dept. of Marketing and Management, L. Chaturvedi, Depts. of Earth Sciences and Civil Engineering, and Chandler Swanberg, Depts. of Earth Sciences and Physics, New Mexico State University

Deep terrestrial heat-flow measurements in New Mexico and neighboring geologic areas
Principal investigator: Marshall Reiter, New Mexico Bureau of Mines and Mineral Resources and Dept. of Geosciences, New Mexico Institute of Mining and Technology

Feasibility study of geothermal energy for heating greenhouses
Principal investigator: Leo J. LaFrance, Dept. of Mechanical Engineering, New Mexico State University

Geothermal resources of New Mexico: A survey of work to date
Principal investigator: William J. Stone, New Mexico Bureau of Mines and Mineral Resources

Geothermal application feasibility study for the New Mexico Institute of Mining and Technology campus
Principal investigator: Alan R. Miller, Dept. of Metallurgy, New Mexico Institute of Mining and Technology

Use of geothermal energy for desalination in New Mexico-A feasibility study
Principal investigators: Lokesh N. Chaturvedi, Depts. of Earth Sciences and Civil Engineering, Conrad Keyes, Jr., Dept. of Civil Engineering, Yash Gupta, Dept. of Chemical Engineering, and Chandler A. Swanberg, Depts. of Physics and Earth Sciences, New Mexico State University

Geothermal potential of Rio Grande rift
Principal investigators: Douglas G. Brookins, Jonathan F. Callender, George R. Jiracek, Albert M. Kudo, Gary P. Landis, and Lee A. Woodward, Dept. of Geology, University of New Mexico

Regional operations research for the development of geothermal energy, southwest United States-A proposal to U.S. ERDA and the Four Corners Regional Development Commission, New Mexico Energy Institute, New Mexico State University

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FIGURE 1– CONTOUR MAP SHOWING ESTIMATED ULTIMATE RECOVERY FOR WELLS IN THE BLANCO MESAVERDE GAS POOL IN NORTHWEST NEW MEXICO

Data based on wells drilled on 320 acre spacing as of December 31, 1974

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CIRCULAR 167 FIGURE 2

Compiled by Louie Martinez, 1977

FIGURE 2—CONTOUR MAP SHOWING AVERAGE DAILY PRODUCTION PER WELL FOR 1976 IN THE BLANCO MESAVERDE GAS POOL IN NORTHWEST NEW MEXICO

Exclusive of infill-well production